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Article

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Research paper

Optimal electricity cost minimization of a grid-interactive Pumped Hydro Storage using ground water in a dynamic electricity pricing environment

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HIGHLIGHTS

- Optimal energy cost control of a grid-interactive PHS using groundwater system is modeled.
- There is potential of more than 68.44% cost saving.
- The system breakeven point compared with the grid is 2.25 years and $7336.
- Payback is reached at 5.9 years of operation.
- Findings show the cost effectiveness of the system under the current South African TOU and FIT.

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ABSTRACT

The electricity price arbitrage from the utility grid can be a major source of revenue for energy storage systems. In most countries, the electricity price is tightly regulated by their government statutory authority or energy regulator to which obey the different power utility and distribution companies. It is worthwhile analyzing whether energy storage systems, such as Pumped Hydro Storage systems (PHS) using ground water, are economically viable in such a given electricity market, and determining what the benefits are of optimally operating these systems in arbitrage environments for privately owned PHS primarily used for auto-consumption or self-sufficiency.

In this paper, an optimal energy control of an 8 kW grid-interactive Pumped Hydro Storage system using ground water in a farming environment is presented. A typical small farming activity within the Mangaung municipality in Bloemfontein, South Africa, is selected as a case study. The aim is to evaluate the potential energy cost saving, achievable using the proposed system. Therefore, the two objectives are to minimize the cost of energy drawn from the utility, while maximizing the energy injected under the Time-of-Use and Feed-in-Tariff schemes. Thereafter, the performance of the developed model to maximize the proposed PHS economic profitability is analyzed through a case study simulated using Matlab. Simulation results show that a potential of 68.44% energy cost saving can be achieved using the proposed system rather than supplying the load demand by the grid exclusively. From the break-even point analysis conducted, it has been revealed that after 2.25 years corresponding to a cost of $7336, the cumulative costs were lower for the proposed system as opposed to the baseline. Furthermore, the payback analysis has shown that the system can be paid off after 5.9 years of operation.

1. Introduction

The current economic growth to which most of the countries are subjected, requires a significant amount of energy (Arndt et al., 2016). This situation results in a series of environmental and energy challenges such as increased CO_2 emissions, reduction in the grid reliability or even discrepancies between the supply and the demand (Kusakana, 2017a).

The mismatch occurring between electricity generation and consumer demand is one of the main operating challenges experienced by any power system (Jurasz, 2017). Demand smoothening can be used to mitigate the effects of fluctuation in demand, resulting in improved capacity factor of the electrical network as well as of the security of energy supply (Arcos-Aviles et al., 2017). This can be realized by a modification in consumption patterns, which could be stimulated by using incentive-based or price-based programs (Yu and Hong, 2017). Time-of-use (TOU) is a category of price-based program, well suited for consumers in the residential

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sector, whereby the electricity has different pricing periods (off-peak, standard and peak periods), encouraging the consumers to shift their electricity usage to off-peak pricing periods (Kusakana, 2017b). This concept can even be taken further using the electricity Real-Time Pricing (RTP) tariffs, where a specific electricity price is allocated to each hour of the year.

For some sensitive consumers (such as commercial loads, industry or farming activities), shifting electricity demand to off-peak pricing periods cannot be implemented without disturbing the proper scheduling of processes, as the instantaneous electricity demand has to be supplied at a specific time when required by the user or the process. Therefore, energy storage systems can be used for demand smoothening, storing energy during low demand and releasing it during peak demand periods. In addition to demand smoothing, energy storage systems can allow consumers who own storage systems to enjoy some economic benefits if the total cost of storing energy is less than the total savings in the energy bills.

Utility-scale energy storage systems for electricity systems mainly include reservoir-based conventional hydropower and compressed air energy storage, whereas batteries and other storing devices have rather small storage capabilities (Gallo et al., 2016). An alternative to traditional hydropower storage (using dams) is Pumped Hydropower Storage systems (PHS), which are currently seen as the most popular technology for bulk electricity storage. Using a pump to elevate water to the upper reservoir, PHS systems give the possibility of storing electrical power by converting it into water potential energy: discharging it using a turbine connected to a generator, they permit the conversion back to electrical power (Kusakana, 2016).

When assessing the potential for implementing PHS, the available different topologies are summarized in Gimeno-Gutiérrez and Lacal-Arántegui (2015) and some of the main advantages for using PHS include the following (Kusakana, 2015a):

- Supporting the penetration of wind, photovoltaic or other variable energy sources; and supporting the deployment of distributed generation systems;
- Increasing the reliability of grid as well as the network efficiency;
- Decreasing the gap between peak and off-peak demand periods, which can streamline the generation profile;
- Pricing arbitrage in the electricity market.

PHS systems, which comprise two reservoirs situated at different elevations, can allow a large amount of the excess power produced during the low demand periods to be stored and reused when needed at a later stage (Kocaman and Modi, 2017). However, PHS technology is very site-specific because it necessitates a minimum height difference between the lower and the upper reservoir as well as significant water capacities (Luo et al., 2015). Furthermore, traditional PHS systems can have some negative impacts on land occupation; environment and can cause relocation (Gimeno-Gutiérrez and Lacal-Arántegui, 2015; Kucukali, 2014).

Unlike traditional PHS, Groundwater Pumped Storage is an option to store and manage significant amounts of energy that is not constrained by topography; therefore, more potential sites are available (Corbijn, 2017). GPHS plants consist of two reservoirs: the upper reservoir is situated at the surface, while the lower reservoir is underground. Although the underground reservoir can be drilled into (Pujades et al., 2017), some of the cost effective options consist of using decommissioned works, such as deep or open pit mines (Menéndez et al., 2017; Erpicum et al., 2017; Winde et al., 2017; Khan and Davidson, 2016). This reduces the negative impacts as compared to traditional PHS as one of the reservoirs is underground. Other advantage are the availability of water in case of emergency and the possibility to capture water in case of storm and avoid flooding. However, the problem with emptying and filling the drilled reservoir is the change of pressure, which may lead to instability of the cavity (Bodeux et al., 2017).

Like battery storage systems, small scale PHS can assist in the demand side by providing the extra energy needed to avoid consumer discomfort or dissatisfaction that may be caused by load shifting during peak-load or pricing period (Kusakana, 2015b). Consumers can store the excess energy during off-peak period and use it later when the load demand is high. This gives consumers the option to manage, at any time, the bi-directional power flow between their systems and the grid (import and export).

In most of the developed countries, the market-oriented electricity arbitrage process is used to promote the development of energy storage systems. From the grid point of view, the presence of arbitrage allows the grid to shift peaking demand by regulating the electricity prices using different strategies such as the TOU (Lin and Wu, 2017). However, an optimal energy control system is required to achieve minimal electricity cost by responding at the same time to the design and operational constraints of the system.

From literature, the optimal control approach has been revealed as a very powerful tool in solving energy management in different sectors. In Middelberg et al. (2009) for example, an optimal control approach has been applied to load shifting with the aim of reducing the energy cost of a colliery. The results obtained using the developed model have revealed a potential reduction of 49% in the energy cost achievable during 5 weekdays in a high-demand period. In Zhang and Xia (2010), a potential reduction of 37.38% in energy cost can be realized on a coal belt conveying system when an optimal control approach is implemented. In Badenhorst et al. (2011), optimal control is implemented in a deep level mine twin rock winder system, with the aim of reducing the cost of the energy consumed. The results have shown that optimal scheduling of the hoist under TOU tariff can result in a potential reduction of 30.8% in energy cost. Authors in Numbi et al. (2014) have demonstrated that applying optimal control to the energy management of a jaw crushing process in a deep mine can result in more than a 50% energy cost saving. In Kusakana (2015c), an optimal switching operating strategy has been applied to a diesel generator with the aim of minimizing the operation costs, subject to the load energy requirements, as well as to the diesel generator and the battery operational constraints. The results show that a minimum of 8% can be saved daily on the operational cost by using a hybrid system, and taking into account the non-linearity in daily load demand and fuel consumption curve. In Numbi and Xia (2015), an optimization model is developed to reduce the energy cost of a parallel HPGR crushing process. The results have revealed that a daily energy cost saving of 41.93% can be realized. The authors in Numbi and Xia (2016) have conducted a study aiming to minimize the energy cost of a crushing circuit based on a vertical shaft impactor. The results have shown that up to a 49.7% energy cost saving can be achieved. The optimal control technique was initially developed to deal with continuous-time problems by using the Pontryagin's maximum method (Pontryagin et al., 1962). However, addressing a continuous-time optimal control problem by this method will consider both objective and constraints to be continuously differentiable. The TOU electricity tariff, being a discrete function, will turn the optimal energy control problem into a continuous but not differentiable problem and having a number of constraints. Therefore, in this work, a numerical approach is suggested as an alternative.

Related to optimal control applied to PHS operation, the authors of Connolly et al. (2011) developed three practical operation approaches i.e. 24 optimal, 24 prognostic, and 24 historical to assess the economical returns for a PHS. From the results, it can be seen that close to 97% earnings can be realized by using 24 optimal strategy based on storing energy on the day-ahead electricity prices.

In Kanakasabapathy (2013), the authors studied the impact of PHS energy trading on the social wellbeing of electricity market by giving a theoretical analysis and intuitive explanation. In addition, a numerical case study was illustrated to validate the analytical results developed. In Crampes and Moreaux (2010), the authors analyzed the efficient operation of the PHS when the outputs at each period are provided. The boundary between the storage and no-storage results and its sensibility to cost variations have been determined. Thereafter, the optimal dispatch given the intertemporal preferences of electricity consumers have been determined. The model gives emphasis to the economic driver of the technology that is the net social gain from transferring social surplus from off-peak to peak period.

In Barros et al. (2003), the authors analyzed the operation of a PHS reservoir with the variables such as water inflow, energy generated and time interval of water inflow by using linear and non-linear programming optimization methods. The simulation results have demonstrated that non-linear programming is well suited for real time operation.

The operation modes, that can be implemented to increase the efficiency while reducing the operation cost of a PHS reservoir by using the different optimization methods, have been reviewed in Labadie (2004). The results have showed that genetic algorithm is more convergent as compared to other methods. In Goor et al. (2010), the authors have presented stochastic dual programming for management of storage systems, which gives more accurate result for maximizing the net production rate. The authors of Shawwash et al. (1999) discussed the linear programming technique for optimizing the day to day power generation and schedules in electricity market. This model was used to determine the optimal scheduling to meet the hourly internal load.

A stochastic dynamic programming model involving the best forecast period of flow, outflow from a hydro storage has been determined for the expected advantage from future operations.

Very few research works have been published on the use of groundwater for electricity generation. In Anilkumar et al. (2017), a model is developed to minimize the electricity cost of domestic consumers where open wells are available. In the studied case, a solar photovoltaic system with ground PHS is used for minimizing the electricity bill in a dynamic electricity pricing environment. The objective function is solved using particle swarm optimization (PSO). The payback period for the proposed supply option, if realized, is also analyzed as a case study in India. A similar study was conducted in Thankappan et al. (2017) where a wind conversion system was used in conjunction with the PV as primary sources of energy. In Kusakana (2017c), a model of electricity cost minimization of a grid-connected PV with borehole as a storage system is proposed for farming communities in South Africa. The optimization problem has been solved using linear programming and the results have been used to investigate the impact and benefit of the proposed model on the electricity cost reduction in the South African farming sector. The same concept has been used in Kusakana (2017d), however, a mechanical wind pumping system has been used instead of PV. In Stoppato et al. (2014) an optimal energy management of a hybrid system composed of a PV, diesel generator with a battery storage system has been proposed. A PAT (Pump as Turbine) is also used as a hybrid system for supplying electricity and water, as well as storing groundwater in the upper water tank. The results have shown that the proposed controlled hybrid PV-PAT storing system is capable of supplying the water for irrigation and domestic requirements as well as 9% of the electricity needed for the selected isolated load. More information on the use of PAT in micro-pumped hydro energy storage is detailed in Morabito et al. (2017).

With the aim of achieving the full earning potential in a given electricity market, PHS owners must actively implement an optimal operation strategy to maximize income by seeking profits. A key research area is therefore, converting PHS scheduling information into an effective energy management strategy to ensure that, in the electricity market, the plant owners achieve maximum benefits. The present paper is focused on the economic viability of storage from the point of view of the storage system's electricity consumer. The consumer can save on the electricity bill by storing electricity during off-peak hours, at a low price and later, during on-peak hours, using the electricity stored to supply the load and avoid purchasing electricity at a high price. In this paper, we study whether the savings on the electricity bills during the lifetime of the storage are enough to compensate for its capital cost and operation and maintenance costs. We show a method to evaluate technically and economically the storage system, comparing it with a system without storage.

Using the above-mentioned information as background, this paper develops an optimal energy management strategy for PHS operation for purchasing and selling electricity in the South African electricity market, taking advantage of the Time of Use and Feed In tariff (FIT). For this purpose, a mathematical model describing the optimal scheduling of PHS to be implemented, is developed. Thereafter, the performance of the developed model to maximize the proposed PHS is analyzed through a case study.

This paper is organized as follows: Section 2 presents the optimal control model of the grid-interactive pumped hydro storage using ground water; Section 3 presents data of the case study used the simulation. The results obtained from the simulations are presented and discussed in Section 4. Lastly, conclusions and recommendations are presented in Section 5.

2. Method

2.1. System description

The energy storage considered in this study is part of the private facility owned by the power consumer. The methodology adopted in this work could be endorsed for any type of energy storage system; however, we will focus on PHS using groundwater. This system consists of two reservoirs; the upper reservoir is situated at the surface (it can also be constructed at a height above the ground level), while the lower reservoir is underground. The other main component of the system considered in this work are Pump as Turbine (PAT) and a control system; which could be used to implement the optimal control model developed in the next sections.

The proposed system is grid interactive (with a bidirectional power flow from and to the grid), as shown in Fig. 1. The load demand (P_L) is principally covered by the PHS through its turbine-generator module (P_{TG}), on condition that there is enough water stored in the tank. When there is more than enough energy in the reservoir to supply the load, the surplus of generated energy (P_{EXP}) is fed into the grid. The power from the grid (P_{IMP}) can be used when there is insufficient energy from the PHS upper reservoir to supply the load, or to drive the water pump when filling the reservoir. The changing electricity tariff plays an important role in determining whether the load is supplied from the grid or from the PHS, as well as in determining the power flow from the grid or into the grid.

The following control variables to be optimized are represented by the arrows in Fig. 1. P_{IMP} is the grid power used to directly supply the load or to drive the motor-pump. P_{PHS} is the power linked to the PHS system which can be positive when power is generated from the turbine-generator set to supply the load or to be exported to the grid; or negative when it is driving the water pump module to fill the upper reservoir: P_{EXP} is the power from the turbine-generator set fed into the grid for revenue (credit) generation.

The operation of the different components of the PHS system are described in the subsections below.

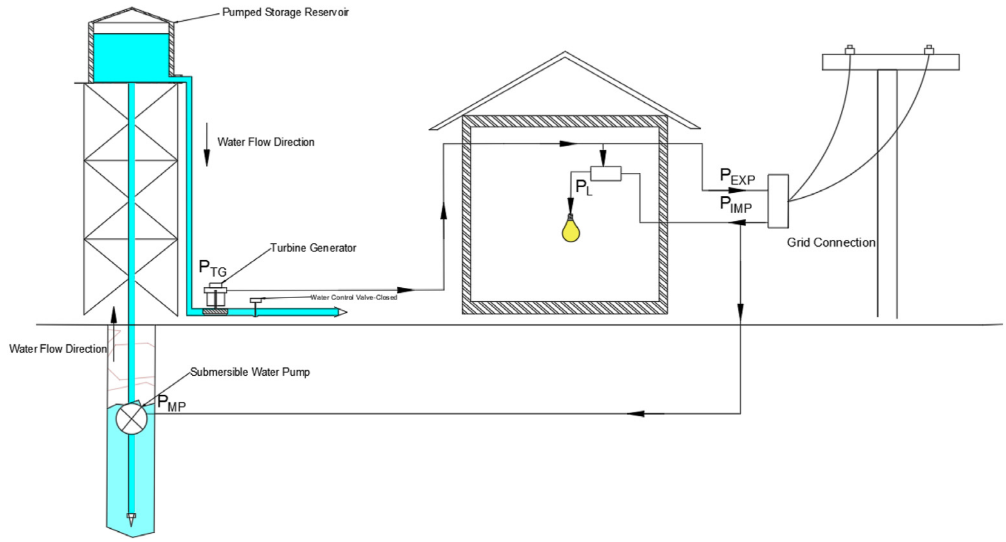

Fig. 1. Schematic diagram of a grid-interactive pumped hydro storage system.

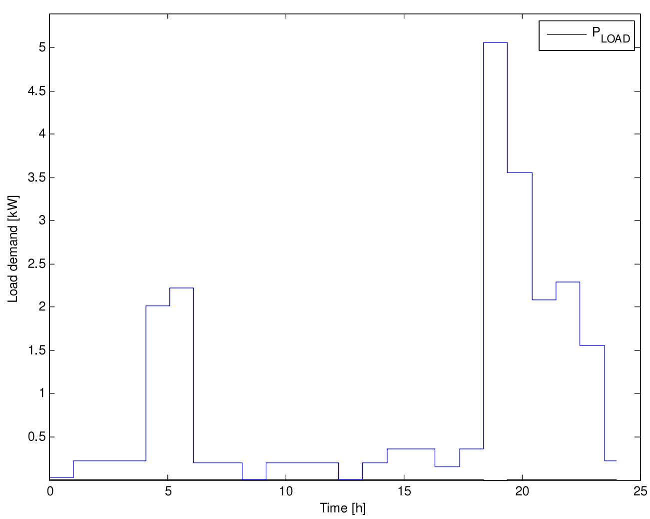

Fig. 2. Daily combined load profile.

2.1.1. Pumping system

The power required to extract water from the source to the upper reservoir (P_{MP}) in kW supplied from the grid is expressed as follows:

$$P_{MP} = \frac{\rho \times g \times h \times Q_{MP}}{\eta_{MP}} \tag{1}$$

where P_{MP} is the input power to the pump (W); Q_{MP} is the pumping flow rate (m^3/s); h is the useful pumping head (m); g is the gravity (9.8 m/s^2); and η_{MP} is the total efficiency of the pumping system.

2.1.2. Pico hydro turbine

The electrical power generated from the pico hydro system P_{TG} is expressed as:

$$P_{TG} = \rho \times g \times h \times Q_{TG} \times \eta_{TG} \tag{2}$$

where η_{TG} is the hydro generating power efficiency; Q_{TG} is the flow rate through the turbine (m^3/s); h is the head (m).

2.1.3. Upper reservoir

The Pico turbine produces electrical power output P_{TG} with efficiency η_{TG}. Therefore, the rated output would be achieved with a water power input P_{In-TG} of:

$$P_{In-TG} = \frac{P_{TG}}{\eta_{TG}} \tag{3}$$

Water is taken from a water reservoir at height h above ground level, to the turbine located at ground level. Taking the density of water ρ and the acceleration due to gravity g, the water flow rate V needed by the turbine of power P (watts) is then:

$$V = \frac{P_{In-TG}}{h \times \rho \times g} \tag{4}$$

The available volume of water stored in the tank is directly linked to the potential energy (E_R) available. This can be expressed as:

$$E_R = \rho \times v \times g \times h \tag{5}$$

where E_R is expressed in kWh and V in m^3.

On top of the water resource available on site, the size of a motor-pump, turbine-generator and the capacity of the PHS system are generally dependent on the funds available, energy saving target and the peak power that is set to be fed to the utility grid. In this work, the peak power is taken as the size selection criterion.

2.2. Model development

Considering the TOU tariff, the cost incurred for the proposed GPHS will be calculated and compared to the case where the consumer is supplied directly from the grid without storage.

The GPHS can generate profit when electricity is purchased from grid during off-peak pricing period (at a low price), pumping water into the upper reservoir, and, later, during peak pricing period (at a high price), generating electricity through the turbine to supply the load or to sell back to the grid. However, the PHS buys more electricity from the grid than it later generates because of the losses of the PAT (pumping and generation mode) pump and the upper reservoir. The electricity generated from the PHS during peak pricing periods can be 65%–90% of the energy purchased from the grid during off-peak pricings periods (depending on the PAT technology) to pump water in the upper reservoir (Bernardo et al., 2017).

If the cost of energy purchased from the grid (to pump water in the reservoir) is less compared to the cost of the energy generated from the turbine (to supply the load and to be sold to the grid) it makes up for the conversion and storage losses, then the total energy purchased from the grid will cost less in the case of the GPHS than in the system without GPHS.

If the cost savings, realized over the operating lifetime, are higher than the cost of the lifecycle costs storage (capital + replacement + operation and maintenance), the proposed GHPS will be profitable.

In the next section, the optimal control model to minimize the operation cost of the proposed system will be developed. This will assist in assessing whether the GPHS is profitable from the point of view of the electricity consumer owning the storage system.

2.2.1. Objective function

The main objective of the control method to be applied to the system is to minimize the net electrical energy cost, "f", over a given period. This is defined as the difference between the energy costs due to the power purchased or imported "P_{IMP}" and the energy cost due to the power sold or exported to the grid (P_{EXP}). This is expressed mathematically as a multi-objective function, as follows:

Therefore, a multi-objective cost function can be derived consisting of two main parts: the first part is the cost of purchasing electricity from the grid, which is used to supply the load demand and fill in the reservoir of the PHS system. The second part is the revenue (credits) generated from selling electricity to the grid.

$$f = \sum_{j=1}^{N} [\rho_j (P_{IMP(j)}) - C(P_{EXP})] \Delta t \tag{6}$$

where j is the jth sampling interval, N is the considered number of sampling intervals, Δt is the sampling time, ρ is the TOU electricity tariff and C is the FIT.

2.2.2. Constraints

2.2.2.1. Load balance. The power balance is one of the key constraints in electrical networks that need to be met. The power balance constraints to be met at main nodes of the system are expressed as follows:

$$P_{Load(j)} = P_{TG(j)} + P_{IMP(j)} \tag{7}$$

$$P_{TG(j)} = P_{EXP(j)} + P_{Load(j)} \tag{8}$$

$$P_{IMP(j)} = P_{Load(j)} + P_{MP(j)} \tag{9}$$

2.2.2.2. Dynamics of PSH water level. During pumping and power generation, the state of water volume, V_R, in the reservoir of the PHS has to be maintained between its minimum and maximum values, V_R^{min} and V_R^{max}, respectively. The state of water volume can be expressed in the discrete-time domain as follows:

$$\begin{aligned} V_{R(j)} &= V_{R(j-1)} \times (1-\delta) \\ &\quad + \frac{\Delta t}{E_m} \times \left(\eta_{MP} \times \sum_{i=1}^{j} P_{MP(j-1)} - \frac{\sum_{i=1}^{j} P_{TG(j-1)}}{\eta_{TG}} \right) \end{aligned} \tag{10}$$

where V_{Rj} is the V_R at the considered sampling interval, j; $V_{R(j-1)}$ is the V_R at the previous sampling interval, $(j-1)$; E_n is the nominal potential energy of the reservoir in kWh; η_{TG} is the efficiency of the hydro generator; η_{MP} is the efficiency of the pumping system, and δ is the evaporation and leakage loss.

By a recurrence, V_R at the considered sampling interval can be expressed as a function of P_{MP}, P_{TG} and its initial value, $V_{R(0)}$, which is constant. This can be expressed as follows:

$$\begin{aligned} V_{R(j)} &= V_{R(0)} \times (1-\delta) \\ &\quad + \frac{\Delta t}{E_m} \times \left(\eta_{MP} \times \sum_{i=1}^{j} P_{MP(01)} - \frac{\sum_{i=1}^{j} P_{TG(0)}}{\eta_{TG}} \right) \end{aligned} \tag{11}$$

With this, the constraints to keep the V_R dynamics within specified boundaries are written as follows:

$$\begin{aligned} V_R^{\min} &\le V_{R(j)} = V_{R(j-1)} \times (1-\delta) \\ &\quad + \frac{\Delta t}{E_m} \times \left(\eta_{MP} \times \sum_{i=1}^{j} P_{MP(j-1)} - \frac{\sum_{i=1}^{j} P_{TG(j-1)}}{\eta_{TG}} \right) \le V_R^{\max} \end{aligned} \tag{12}$$

2.2.2.3. Power flow boundaries. For safety considerations, all power flows linked to the different components should be kept within boundaries according to the manufacturer's specifications. These constraints can be expressed as follows:

$$P_{IMP}^{\min} \le P_{IMP(j)} \le P_{IMP}^{\max} \tag{13}$$

$$P_{EXP}^{\min} \le P_{EXP(j)} \le P_{EXP}^{\max} \tag{14}$$

$$P_{IMP}^{\min} \le P_{IMP(j)} \le P_{IMP}^{\max} \tag{15}$$

$$P_{MP}^{\min} \le P_{MP(j)} \le P_{MP}^{\max} \tag{16}$$

2.2.2.4. Exclusive power flow between grid and pumped hydro storage. On the one hand, since the customer cannot purchase and sell power at the same time, the product between the sum of power from the grid, and the sum of power to the grid, at a specific sampling time "j" has to be zero. This is mathematically expressed as follows:

$$P_{IMP(j)} \times P_{EXP(j)} = 0 \tag{17}$$

On the other hand, the motor pump and the turbine generator sets of the PHS cannot operate at the same time. This is mathematically expressed as follows:

$$P_{G-MP(j)} \times P_{TG(j)} = 0 \tag{18}$$

2.2.2.5. Fixed-final state condition. For proper planning and operation purposes, in order to take into consideration repeated implementation of the optimal energy control of the grid-interactive pumped hydro storage system, the potential energy of water stored in the reservoir at the end of the control horizon should be equal to the potential energy of the stored water at the beginning of the control horizon. This is the same as equating the V_R at the last sampling interval, $V_{R(N)}$, to the initial state condition, $V_{R(0)}$. This requirement results in the development of the constraint below:

$$\sum_{j=1}^{N} (P_{TG(j)} + P_{MP(j)}) = 0 \tag{19}$$

2.2.3. Proposed algorithm

The developed objective function and constraints are linear. Therefore, the optimization problem can be solved using fmincon in Matlab (Lin and Wu, 2017):

$$\min_x f(x) \text{ Subject to: } \begin{cases} c(x) \le 0 \\ c_{eq}(x) = 0 \\ A.x \le b \\ A_{eq}.x = b_{eq} \\ l_b \le x \le u_b \end{cases} \tag{20}$$

where: x, b, b_{eq}, l_b, and u_b are vectors; A and A_{eq} are matrices; $c(x)$ and $c_{eq}(x)$ are functions that return vectors and $f(x)$ is a function that returns a scalar.

3. Case study

To evaluate the effectiveness of the model developed in Section 2, a grid-interactive pumped hydro storage system was installed in a small farm in the Mangaung municipality of Bloemfontein in South Africa. The South African case was selected because the electricity prices have increased by over 300% since 2007.

Given the current electricity price in South Africa, the proposed supply system with the developed energy control model has the potential of reducing the operation cost. This might increase the economic profit of farmers who can select this grid connected supply option.

The load profile and size of each component of the system under consideration are presented below.

3.1. Load profile

Two types of load are generally found in different farms; these are the primary (critical) and secondary (non-critical) loads. The primary loads are those of high priority that must always be supplied, shifted or reduced, while the secondary loads can be managed without causing substantial discomfort to the farm.

The primary load on the considered farm consists of the bulk milk cooler, milking machine, fan, water pump, freezer, electric fence and light, while the secondary load consists of equipment such as a stove and electric water heater. On the considered farm, Demand Side Management technics are applied to the non-critical load, keeping it switched-off during the day and operating it at night when the total demand as well as the price of electricity is low.

During the day, only the required energy is consumed by the primary load since only the milk cooler is operated, while most of the other equipment are also operated during the evening and night.

Data to draw the load profile has been gathered by using Single-phase Energy E2 Classic energy monitors with 2% measurement error. The load profile is shown on Fig. 2.

3.2. System sizing

The size of a grid-interactive pumped hydro storage system is mainly dictated by the funds available to implement the project, energy saving target, the specifications of the site where the system needs to be built and the maximum amount of power to be fed into the utility grid. In this work, the maximum amount of power to be fed into the utility grid is taken as the size selection criterion. The methodology for sizing the system is explained from reference (Kusakana, 2015b). To take advantage of the FIT incentive offered by Mangaung municipality, a grid-interactive PHS system with a capacity of 8 kW is to be installed on the selected farm. With this, the size (rating) of the system's different components are given on the table below:

3.3. Electricity tariffs

In South Africa, the National Energy Regulator (NERSA) opined that priority to feed power to the grid must be given to consumers on the TOU tariff as this reduces stress caused to the national grid by peak load demands (Numbi and Malinga, 2017). In some regions of South Africa, the peak price of electricity is significantly higher than the off-peak price, which leaves room for arbitrage.

The considered electricity tariff used in Bloemfontein can be found in Kusakana (2017e). The FIT incentive for residential embedded generation used in the Mangaung municipality is USD 0.046/kWh.

The adoption of the demand-side management activities in South Africa has allowed electricity users to have the opportunity to select either flat or TOU tariffs. Unlike with the flat tariff, with a TOU tariff users are billed at different rates depending on the different daily pricing periods. Moreover, the TOU tariff also varies depending on the season; higher in winter than in summer.

The TOU tariff, for residential customers in summer (from 01 September to 31 May) is given as follows (Oscar, 2017):

Table 1
Simulation parameters.

Item	Figure
PAT	8 kW
Simulation sampling time	30 min
Pumping efficiency	75%
Pico turbine efficiency	70%
Reservoir capacity	9.2 kWh

$$\rho(t) = \begin{cases} \rho_k;\ t \in T_k, T_k = [7, 10) \cup [18, 20) \\ \rho_0;\ t \in T_0, T_0 = [0, 6) \cup [22, 24) \\ \rho_s;\ t \in T_s, T_s = [6, 7) \cup [10, 18) \cup [20, 22) \end{cases}$$

The TOU tariff for winter period (from 1 June to 31 August) is given as follows:

$$\rho(t) = \begin{cases} \rho_k;\ t \in T_k, T_k = [6, 9) \cup [17, 19) \\ \rho_0;\ t \in T_0, T_0 = [0, 6) \cup [22, 24) \\ \rho_s;\ t \in T_s, T_s = [9, 17) \cup [19, 22) \end{cases}$$

where $\rho_k = 0.16$ \$/kWh (summer) or 0.24 \$/kWh (winter) for peak periods;

$\rho_0 = 0.06$ \$/kWh (summer) or 0.07 \$/kWh (winter) for off-peak periods;

$\rho_s = 0.08$ \$/kWh (summer) or 0.11 \$/kWh (winter) for standard periods.

4. Simulation results and discussion

The open-loop optimal control problem used in this work is solved off-line over a control horizon of 24 h using the sampling time given in Table 1. This means that the optimal solution over the proposed control horizon is obtained once and thereafter applied to predict the future states/outputs of the system. In other words, the control actions are applied ahead of time to the process, due to the off-line nature of the open-loop optimal control strategy.

In this section, simulation results of the proposed grid-interactive PHS systems operating under TOU tariff are presented. The results are also compared to the case where the grid alone is used to supply the load. Sensitivity analyses are also conducted on the initial state of volume (potential stored energy) of the upper storage reservoir.

The simulation is performed for the worst case demand on a day in the winter season (01 August 2016) with a considered control horizon of 24 h. The same procedure can be adopted for a summer case with the corresponding seasonal TOU and FIT. More explanation on the simulation parameters used can be found in Kusakana (2017c).

4.1. Baseline: Load exclusively supplied by the grid

In order to analyze the effectiveness of the developed model, the daily operational cost achieved through optimal energy control of the proposed system is compared to the energy cost incurred by the farming load supplied by the grid exclusively.

Fig. 3 shows the simulation results of the case where the grid is used exclusively to supply the load demand of Fig. 2. It can be observed that the power profile drawn from the grid and the load profile have an identical pattern. The analysis of this figure reveals that the peak load demand coincides with the peak pricing period from the grid and this will result in high cost of electricity consumed.

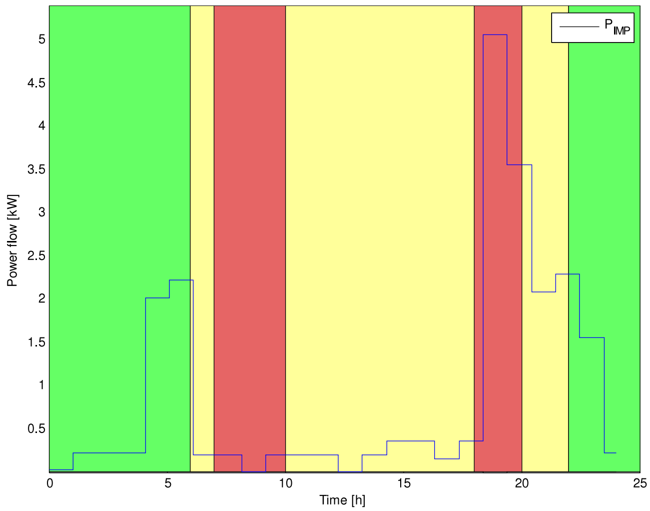

Fig. 3. Power flow of grid exclusively supplying the load (Baseline).

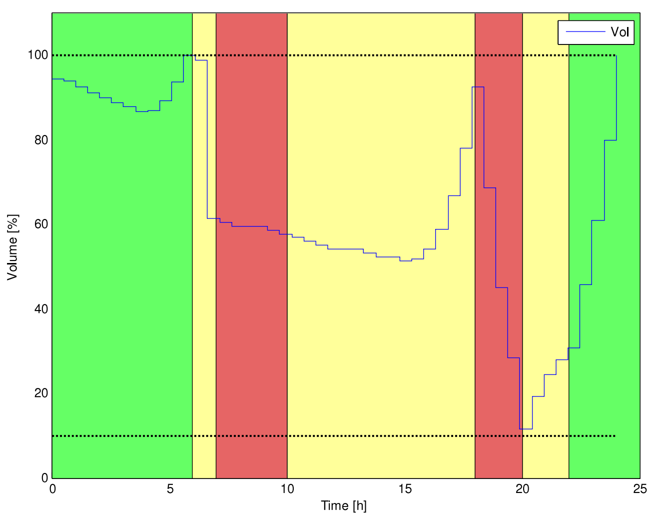

Fig. 4. PHS water volume dynamic . (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

4.2. Load supplied by the grid-interactive PHS (summer).

In this case we consider that, at the beginning of the simulation, the state of volume in the water tank is set at its maximum.

• Optimal power flow during first Off-peak pricing period (green)

Given the fact that the initial water level in the tank is at its maximum, as shown on Fig. 4, the energy generated by the pumped hydro storage system is used to supply the demand and to be exported to the grid, as shown on Fig. 5 and Fig. 6 respectively. Therefore, there is no energy imported from the grid to supply the load or pump water in the reservoir, as shown on Fig. 7.

However, towards the end of this first off-peak pricing period, an increase in the load demand can be noticed from 04h00 to 06h00. Therefore, the power is imported from the grid, as shown of Fig. 7, to supply the load as well as to fill the reservoir as shown on Fig. 4 where the dynamic of the storage reservoir indicates an increase in the water level. This can also be seen on Fig. 5 where the negative power flow can be interpreted by the direction of power flowing into the PHS.

• Optimal power flow during first Standard pricing period (yellow)

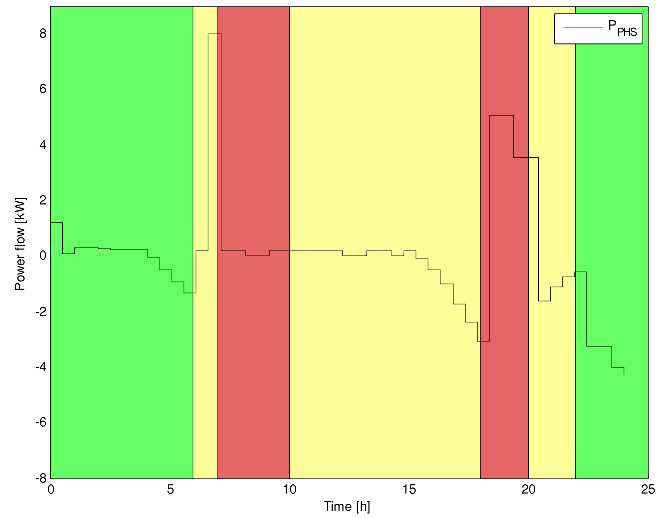

Fig. 5. Optimal power flow of the PHS . (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

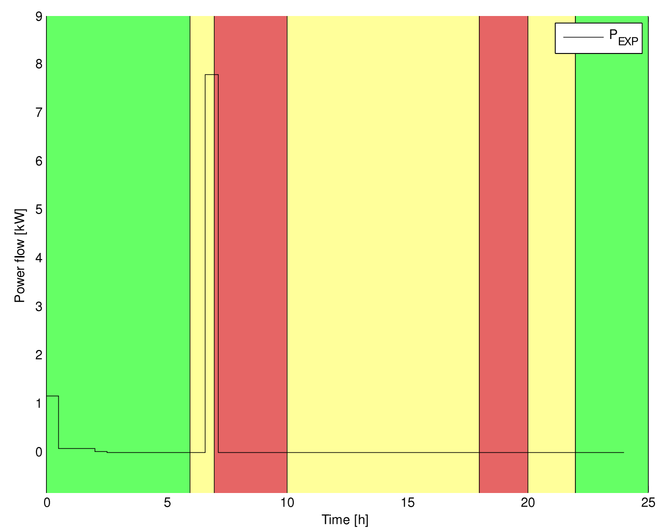

Fig. 6. Optimal power flow of exported power to the grid . (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

During this standard pricing period, the total load demand is low, as shown on Fig. 2. Therefore, the demand is successfully met by the PHS, as shown on Fig. 5. Because the Feed-in tariff is acceptable, power from the PHS is exported to the grid, as shown on Fig. 6. The power produced by the PHS to supply both the load and to be exported can be interpreted on Fig. 3, where a decrease of water level in the storage system can be observed.

In the pricing period, there is no power imported from the grid, as shown on Fig. 7.

• Optimal power flow during first Peak pricing period (red)

During this peak pricing period, the load is low and mainly supplied by the PHS, and the associated state of volume decreases as shown on Figs. 4 and 5 respectively. There is no power exported to the grid or imported from the grid as shown on Figs. 6 and 7 respectively.

• Optimal power flow during second Standard pricing period (yellow)

In the beginning of this second standard pricing period, the load demand is low, therefore, it is mainly supplied by the PHS as shown on Figs. 4 and 5.

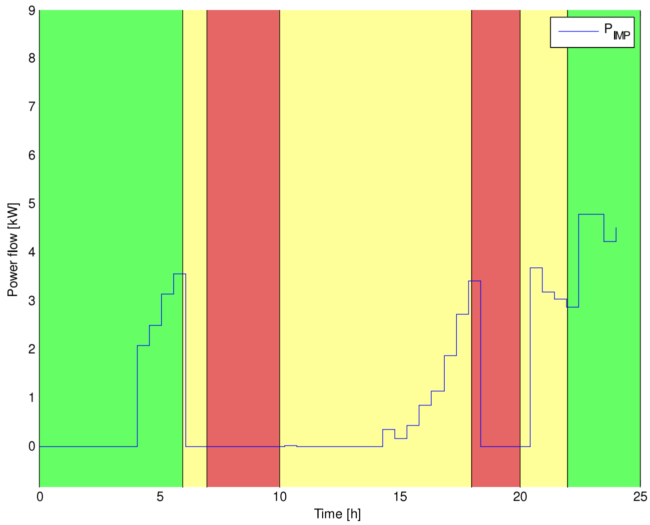

Fig. 7. Optimal power flow of imported power from the grid . (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

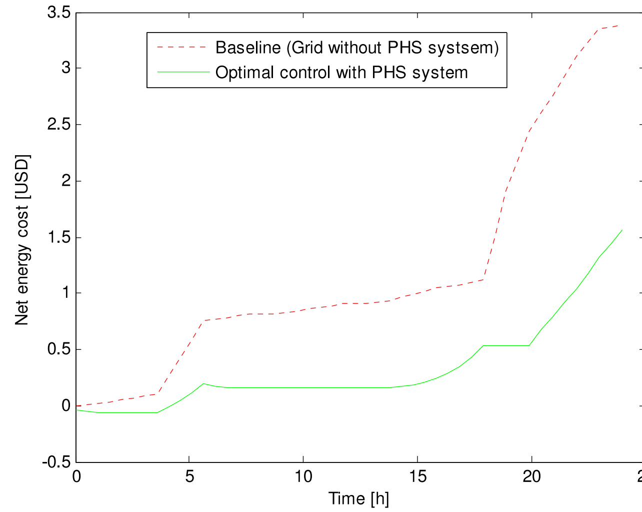

Fig. 8. Cumulative net energy cost with initial reservoir volume at 100% of maximum capacity.

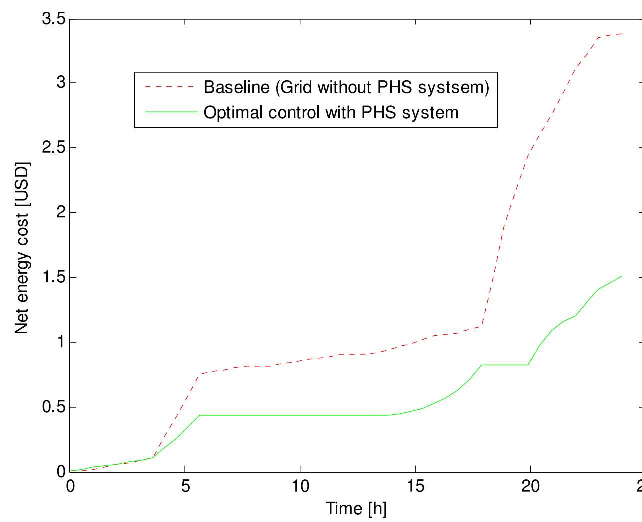

Fig. 9. Cumulative net energy cost with initial reservoir volume at 50% of maximum capacity.

Towards the end of this pricing interval, Fig. 7 shows that due to the reasonable TOU tariff, power is imported from the grid to supply the load as well as to pump water into the upper reservoir. This results in an increase of the water level in the storage tank corresponding to a negative power flow in the PHS, as shown on Figs. 4 and 5 respectively. Fig. 6 shows that no power is exported to the grid to ensure enough energy is stored to prepare for the coming peak period.

• Optimal power flow during second Peak pricing period (red)

During this pricing period, the load demand and the cost of electricity from the grid are both high. Therefore, to reduce the peak energy demand from the grid, the load is mainly supplied by the PHS which is discharged at a high rate and the associated state of volume decreases as shown on Figs. 4 and 5 respectively. There is no power flowing to the grid or from the grid as shown on Figs. 6 and 7.

• Optimal power flow during third Standard pricing period (yellow)

During this third standard pricing period, Fig. 7 shows that power is imported from the grid to supply the load as well as to pump water in the upper reservoir. This can be seen on Figs. 4 and 5 by the increase of the water level in the storage tank and the corresponding negative power flow linked to the PHS.

• Power flow during second Off-peak pricing period

Given the fact that the electricity cost is affordable during this period, the power is imported from the grid as shown on Fig. 7 to supply the load. The grid power is also used to drive the pump and fill the tank so as to meet the fixed-final water level condition in order to take into consideration repeated implementation of the optimal energy control model, as shown on Figs. 4–6.

4.3. Economic analysis with sensitivity analysis

4.3.1. Annual cost saving

Table 2 summarizes the cost saving (credit) that can be realized by using the proposed grid-interactive pumped hydro storage operating under the developed model instead of supplying the load exclusively by the grid (baseline). From this table, it is observed that sensitivity analysis has also been made on the impact of the initial state of the water stored in the reservoir (100%, 50% and 10%). The annual cost of energy consumed (and savings) can be computed by multiplying the daily energy cost by the number of days in the 2016 year (274 days in summer and 92 days in winter).

4.3.2. Daily net energy cost comparison

Fig. 8, with the initial reservoir volume at 100% of maximum capacity, shows that the optimal control achieves better cost throughout the day when compared to the baseline.

From Fig. 9, where the initial reservoir volume is at 50% of maximum capacity, it can be seen that for the two first hours of the simulation horizon, the baseline is slightly better than the optimal control; thereafter, they achieve the same performance for the subsequent two hours. Cost saving is realized after 04h00 when the optimal control strategy starts performing better than the baseline.

From Fig. 10, where the initial reservoir volume is at 50% of maximum capacity, it can be clearly seen that for the first 5 h of the simulation horizon, the optimal control strategy is performing poorly when compared to the baseline. This is due to the fact that the grid has to supply the load and to provide extra power to pump water into the reservoir to cater for the upcoming peak period.

These results obtained on Table 2 and Figs. 8–10 also show the relation between the pumped hydro initial state of water stored in the upper reservoir and the cost reduction achieved.

Table 2
Annual energy cost saving.

Strategy	Energy cost (\$/Day)	Energy cost (\$/Year)	Saving (%)
Baseline: Grid only	5.718	2 092	/
CASE I: Initial volume = 10%			
Optimal control Summer	3.779	3.779 × 274 days = 1 035.446	/
Optimal control Winter	6.024	6.024 × 92 days = 554.208	/
Optimal control total net cost	/	1 589.654	24.01
CASE II: Initial volume = 50%			
Optimal control Summer	2.673	2.673 × 274 days = 732. 402	/
Optimal control Winter	4.045	4.045 × 92 days = 372.14	/
Optimal control total net cost	/	1 107.542	47.06
CASE III: Initial volume = 100%			
Optimal control Summer	1.624	1.624 × 274 days = 444.976	/
Optimal control Winter	2.338	2.338 × 92 days = 215.096	/
Optimal control total net cost	/	660.072	68.44

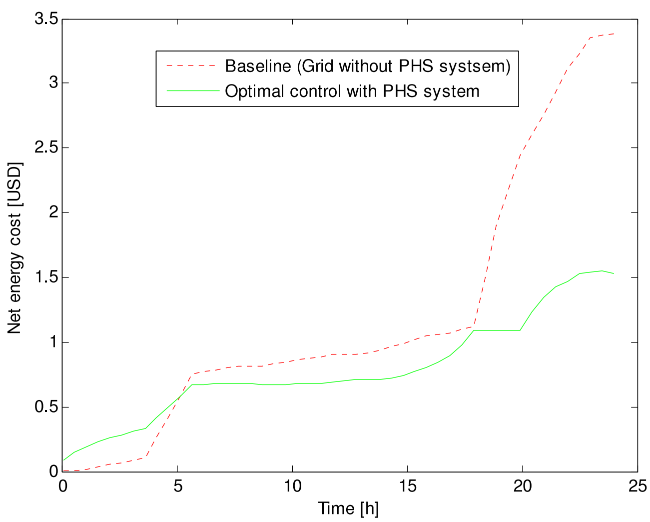

Fig. 10. Cumulative net energy cost with initial reservoir volume at 10% of maximum capacity.

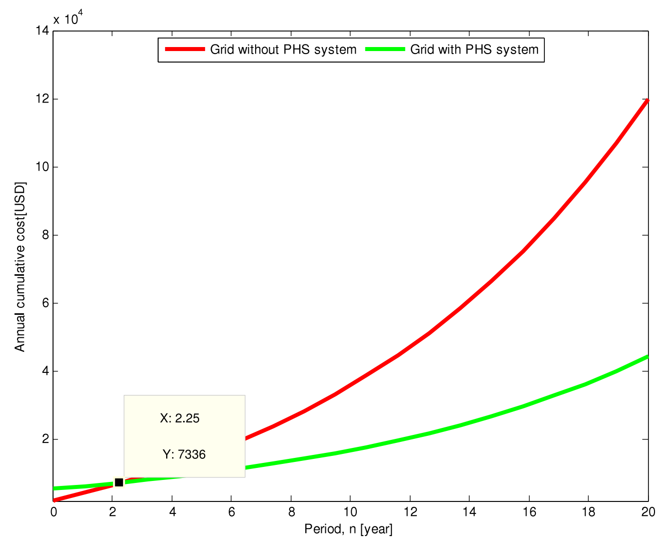

Fig. 11. Breakeven analysis.

4.3.3. Breakeven cost analysis

The break-even point is determined when the lifecycle costs (including capital, operation, maintenance, replacement and salvage costs) of the two systems are equal. This can also give an indication of when the occurrence will take place after the start of the project.

The lifecyle cost curves for both supply options are computed for a duration of 20 years. Even though traditional PHS have reported lifetimes above 50 years, some of the components will need to be replaced before the end of the project. In addition, traditional PHS are not used with many cycles per day as what the simulation results have revealed. Therefore, project duration between guaranteed lifespan and actual reported lifespan was chosen.

In the case where the load is exclusively supplied from the grid, there are no initial, replacement and maintenance costs. Therefore, the cumulative costs incurred over a 20-year lifespan for the baseline system is linked only to the annual electricity purchased from the grid, (calculated in point 4.3.1), with an increase of 10% annually taken into account.

In the case of the grid connected GHPS, the capital cost ranges from \$353/kW to \$2,216/kW with median cost of about \$615/kW which will be used in this work as GHPS, in most of the cases, require less civil works compared to traditional PHS (Oscar, 2017). In terms of maintenance costs PHS facilities have a distinct advantage over the long term; with literature reporting various costs ranging from \$2.12/kW to \$5.64/kW per year (Oscar, 2017). As for the baseline, the same methodology for the cumulative electricity cost with an annual 10% increment is used for the hybrid system.

In the analysis below, the worst case initial, operation and maintenance costs will be used for analysis and comparison with the baseline option. From Fig. 11, it can be seen that the break-even point occurs after 2.25 years with a corresponding cost of \$ 7 336. After this point, the use of the GHPS becomes more economical that the grid alone.

4.3.4. Payback period

In order to reduce the margin of error, a project lifetime of 20 years was chosen for the hybrid system, the reason being that the PAT lifetime is guaranteed for 10 years, however several cases have seen the lifetime reaching over 30 years. Hence, the average number of years between guaranteed and actual reported lifespan was chosen. All salvage costs of components in the payback period calculation are neglected due to the full usage of the components over the 20-year lifespan; so that nothing will be salvaged. The replacement cost is calculated using Eq. (21). With the average inflation rate (from 1998 to 2017) of 5.49% (Bernardo et al., 2017), the future costs of components can be predicted. The total replacement costs (C_{rep}) of all components in the system in the 20-year lifespan are added to the initial investment cost to get total lifetime cost (PC_{TC}).

$$C_{rep} = C_{cap} N_{rep} \tag{21}$$

Table 3
Payback period for the GPHS.

Parameters	Value
Total initial investment cost (USD)	4920
PHS system lifetime, n (years)	20
PHS system connected to grid, lifetime, n (years)	20
N_{rep-SC} (-)	0
C_{rep-SC} (USD)	0
AB (USD)	1386.81
PW_{TC} (USD)	4920
PW_{TB} (USD)	16586.25
PW_{TB-ave} (USD)	829.3125
"True" PBP (years)	5.93

where: Cc_{ap} is the initial capital cost for each component (given in Table 3),

N_{rep} is the number of component replacements of the 20-year lifetime.

Annually, the PHS system's operation and maintenance costs are 45.12$. The annual benefit ($AB$) can be calculated by deducting the maintenance costs from the annual electricity savings as shown in Table 3. The maintenance costs are subtracted from the annual savings (1431.93$), so that the annual benefit (AB) will be 1386.81$. PW_{TC} denotes the total costs of the hybrid system over a 20-year lifespan. The total benefits (PW_{TB}) over the 20-year project span with the average inflation rate in mind, can be calculated using Eq. (22)

$$PW_{TB} = AB\left[\frac{(1+r)^n - 1}{r(1+r)^n}\right] \tag{22}$$

where: r is the average inflation rate over the past 20 years, n is the number of years in the project lifetime.

With the PW_{TB} known, the average annual benefits PW_{TB-ave} can be calculated with Eq. (23)

$$PW_{TB-ave} = \frac{PW_{TB}}{n} \tag{23}$$

where n is the project lifetime in years, subsequently the true payback period (*"True" PBP*) can be calculated with Eq. (24)

$$\text{"}True\text{"}PBP = \frac{PW_{TC}}{PW_{TB-ave}} \tag{24}$$

The *"true" PBP* obtained in Table 3, presents that in 5.93 years the whole project will be paid off in savings.

5. Conclusions

In this study, an optimal energy model of an 8 kW grid-interactive pumped hydro storage system under the FIT has been proposed. This model aims to minimize the cost of energy purchased for the grid while maximizing the cost of energy sold to the grid. A daily load profile compiled using the demand of different equipment and activities on a selected farm in Bloemfontein has been considered as a case study. Since the proposed system has an energy storage device, it is assumed that the farm uses power from the grid under the time-of-use electricity tariff (TOU).

The simulation results showed that when using the pumped hydro storage connected to the grid, it is possible to reduce the cost of energy consumed by the load by up to 68.44%, when compared to the case where the load is supplied exclusively by the grid.

From the break-even point analysis conducted, it has been revealed that after 2.25 years corresponding to a cost of $ 7 336, the cumulative costs were lower for the proposed system as opposed to the baseline.

Furthermore, the payback analysis has shown that the system can be paid off after 5.9 years of operation.

The model developed in this work can also be used to:

- Analyze the impact of the initial state of water stored in the reservoir on the operational cost savings.
- The impact of the feed in tariff on the cost effectiveness of the grid-interactive pumped hydro storage.

It should be noted that the resulting cost of energy consumed is highly dependent on variables such as the load profile, the size of the pumped hydro storage turbine-generator setup, the water pump setup, the reservoir or even the initial potential energy stored in the reservoir.

From the results obtained in this work, the following recommendations are suggested in order to make the implementation of grid-interactive small pumped hydro storage system economically viable, especially in the case of the South African farming sector:

- Net metering should be introduced where consumers can sell electricity at the same price at which they purchase a kWh from the grid.
- The government should initiate funding programmes supporting the initial investment in the proposed system to assist these projects to be cost effective.

The optimal control model developed in this study is open loop. Therefore, if in some cases, during the operation, the control system is affected by external disturbances, the open-loop optimal control will not be capable of updating its control actions in order to respond to these unplanned alterations. Based on this, a Model Predictive Control (closed loop) will be developed for real-time control implementation.

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