Optimization-based Scheduling of Ingula Pumped Storage Plant under Demand Uncertainty

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Abstract

Electrical energy storage is one of the promising solutions of the irregular electricity demand issue. Pumped-storage plants account for most of the storage capacity worldwide. It is popular for high capacity, good responsiveness and high efficiency. It can smooth peak loads, therefore plays a vital role in balancing the grid loads and enhancing the grid availability. A pumped-storage station can be operated in generation, pumping or idle states. In order to obtain an optimal plant schedule, a stochastic optimization model is proposed and the sample average approximation method is applied. The proposed model is used to determine the number of units to be hourly scheduled in generation or pumping mode. The model aims to minimize a supply-demand disparity and shortfall function as a weighted score taking into account the hourly grid demand. Furthermore, the model considers the grid demand uncertainty by considering the main two different demand scenarios "Winter and Summer", and many constraints which are limiting the operation of a pumped-storage station. The model is solved optimally with a case study derived based on the Ingula pumped-storage station in South Africa. Results show that our model proposes pumping-generating schedules that could eliminate the disparity between demand and supply for both summer and winter demand profiles. Furthermore, it could provide a robust schedule that could work for both demand scenarios.

Keywords
Pumped-storage station, Optimal pumping and generation scheduling, Energy storage, Mixed integer programming optimization, Demand uncertainty

1. Introduction
Electrical energy demand is increasing exponentially all over the world and especially in Africa. For example, the total electricity consumption for South Africa recorded a growth of 17% from 265,457 GWh in 2013 to 310,410 GWh in 2017 (Eskom[a]). Similarly, the grid peak load follows an increase pattern with growth of 37% from 37,500 MWh in 2017 to 61,596 MWh in 2030 (Eskom[a]).

Due to the fact that electricity demand is not constant, different types of power stations are required to meet this fluctuating demand. It is important that the amount of electricity needed at any point in time should be matched by the amount generated to provide a balance between supply and demand. Thus, the concept of "peak load stations", which can react swiftly to sudden increases or decreases in demand, is introduced (Eskom[b]). Obviously, an energy storage

system that generates or provides power when demand increases and absorbs or storages power when demand decreases is needed.

Energy storage is classified as one of the most important parts of the future smart grid (Haider *et al.*, 2016). However, energy storage technologies are currently at the research and test stage. Pumped-storage station (PSS) is the most widely adopted large-scale technologies for electricity storage (Yang and Jackson, 2011). Furthermore, it is one of the peaking power stations in South Africa.

A PSS is an energy storage system with water being recycled between an upper reservoir and a lower reservoir or water source. A PSS can be operated in generation, pumping or idle states. A PSS pumps water into its reservoir during the period of low demand and low cost, and discharges water for generation at how of high demand and high cost. It can therefore smooth peak loads, provide reserve and play an important role in reducing the demand-supply mismatch. During off-peak periods, when customer demand for electricity has decreased, the reversible pump/turbines use electricity from the national grid to pump water from the lower to the upper reservoir ready to generate again when needed (Pumping mode). During periods of emergency or peak demand, this water is allowed to run back into the lower reservoir through the turbines to generate electricity (Generating mode). In this way, the potential energy of water stored in the upper reservoir is released and converted into electricity when needed. Because it is necessary to pump the water back after use, pumped-storage power stations can only provide energy for limited periods of time. Over the weekend, when system demand is low, it is necessary to pump for many hours to ensure a full capacity at the stations by Monday morning so that these stations can generate power when needed during the week when electricity demand is higher. Fig. 1 presents a scheme of the pumped hydro storage system.

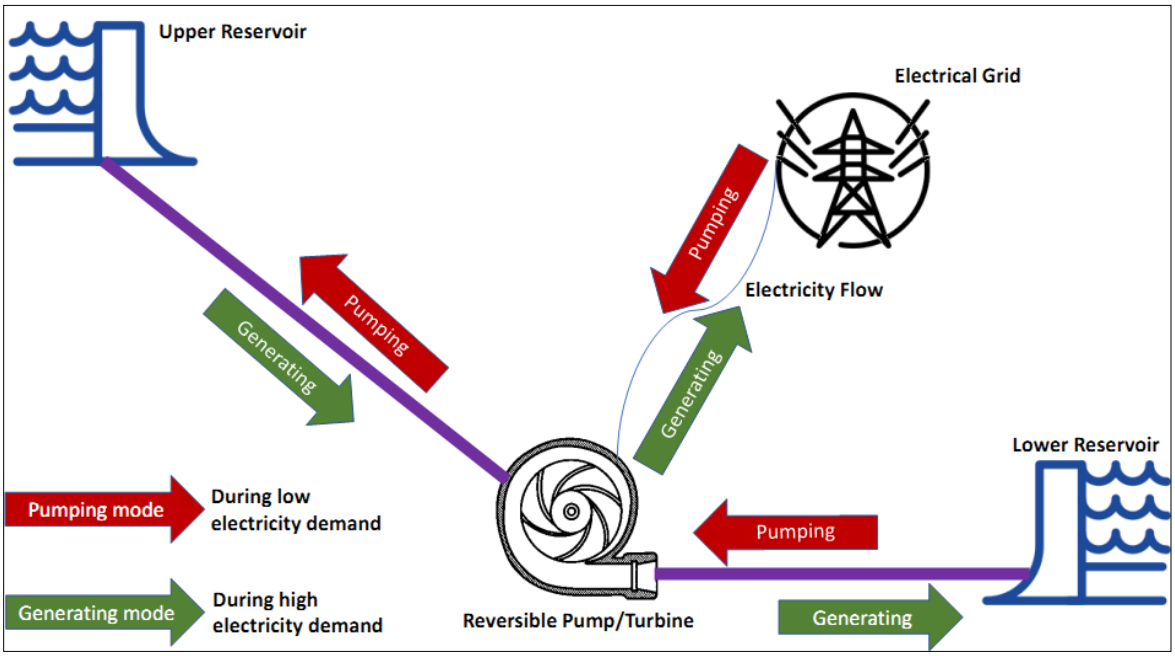

Fig. 1. Schematic representation of a pumped hydro storage system

Comparing to Nuclear and Coal-fired power stations, the PSSs respond very quickly to changes in the demand for electricity. They can be brought on-stream within three minutes and play a major role in maintaining the stability of the grid (Eskom[b]). However, they are more expensive to operate than conventional hydro-electric power stations because of the pumping costs (Eskom[b]).

The majority of the publications related to the PSS Scheduling Problem (PSSSP) investigated merging the PSS with other power systems (i.e., hydro-thermal system) or renewable energy systems (i.e., wind powers system). Guan *et al.* (1994) presented an optimization-based method for scheduling a combined hydrothermal power system with pumped-storage station. They applied the lagrangian relaxation framework and a quadratic approximation function to handle

the complexities in the problem. The problem complexity raises from involving continuous pond level dynamics and constraints, discontinuous generation and pumping operating regions, and dynamic transitions among operating states (generation, pumping and idle). The basic idea of their method was to relax the pond level dynamics and constraints by approximate the water-power conversion. The model objective function was to minimize the operating cost of the thermal power system under the combined system constraints.

Brown *et al.* (2008) formulated a linear programming optimization problem to determine both the power capacity, in MW, and the best reservoir capacity, in MWh, for a potential pumped storage station in an island system. They addressed the stochastic nature of load and renewable production in the optimization problem. They aimed to minimize the sum of operating costs and installation costs. They concluded with that including pumped storage can be an effective means of allowing larger penetration of intermittent renewable energy sources, improving both the dynamic security and the economic operation of a test system. Garcia-Gonzalez *et al.* (2008) investigated how adding a hydro pumped-storage station could support a wind farm and increase level of wind penetration in power systems. They developed a linear programming optimization model as a two-stage stochastic programming problem with two random parameters: market prices and wind generation. Their model aimed to maximize the income for both the wind farm and the proposed pumping utility independently. Similarly, Jiang *et al.* (2012) tested how considering a pumped-storage station could affect the operating cost of a wind power system and influence wind power output reliability under uncertain circumstances. They proposed a robust optimization approach to accommodate wind output uncertainty and minimize the total cost under the worst wind power output scenario.

Koko *et al.* (2017[a]) investigated which of the three residential, commercial and industrial load profiles is the most fitting to be supplied by pumped-hydro storage system under the time-of-use (TOU) tariff scheme. Hence, they proposed a pumped-hydro storage hybrid system and tested it under the different load profiles for the three sectors in South Africa. In a micro-level of the PSS applications, Koko *et al.* (2017[b]) presented a TOU-based optimal energy management model to minimize the electricity cost for a commercial consumer without selling energy to the grid. The developed optimization model revealed the cost saving benefit by maximizing the energy usage from the PSS and by minimizing the grid energy usage especially during the costly standard and peak periods. In another application field, Kusakana (2017) proposed a model to minimize the electricity cost of proposed farming activities in South Africa through the usage of a "Hydro Aeropower" system (Wind pump with Pico hydro generator and a borehole in pumped hydro storage configuration). This model aimed to optimally schedule the generation power flow from the Pico turbine given the demand, the state of water level in the reservoir as well as the electricity pricing period.

Lu *et al.* (2003) developed an algorithm to maximize the profit of a pumped-storage station while conducting optimal pumped-storage station bidding strategies. In their study, they considered the demand as a deterministic variable which argues a limitation for their model.

However, the electricity demand is a dynamic parameter in hourly and daily basis. For example, demand changes from peak to off-peak hours. Also, the demand changes over the weekdays, weekend, vacations, summer, and winter. To the best of our knowledge, considering the demand uncertainty while scheduling the PSS as a standalone system has not been considered earlier in the literature. Thus, there is a need to model the electricity demand uncertainty in hourly and daily basis. Furthermore, most of the studies considered financial related objective functions. However, and as mentioned by Jiang *et al.* (2012), the operating costs for pumping or generating power by the PSS are usually very low. Therefore, there is a need for service related objective functions.

Henceforth, this paper aims to develop a mathematical optimization model for the Stochastic Pumped-Storage Station Scheduling Problem (SPSSSP) to determine the number of units to be hourly scheduled in generation or pumping mode. A mixed integer programming model based on the Sample Average Approximation approach is proposed to consider the uncertainty in grid demand. The proposed model considers a proposed objective function that aims to minimize a weighed supply-demand disparity and shortfall function. The weighting factor depends mainly on the hourly grid demand. The proposed objective function is a service level measure of performance rather than a financial one. The proposed model is solved optimally for the main two different demand scenarios "Winter and Summer". Furthermore, it could provide a robust schedule that could work for both demand scenarios. In the remaining part of this paper, we describe the proposed mathematical formulation in Section 2. A Case study and computational results are shown in Section 3, and finally, in Section 4, we conclude our research.

2. Proposed mathematical model

In this paper, a stochastic mixed integer linear programming model to proposed for the PSSSP with uncertainty in grid demand. As discussed above, the PSSSP is concerned with the decision of selecting an optimal pumping and generation schedule under given capacities and other constraints. The considered PSSSP consists of determining how many units work in pumping or generation mode at time *t* under scenario *i*. The objective function in this model aims at minimizing the weighted sum of the disparity between the station demand and the power generated ($z_{i,t}$). Where the former represents the shortage of energy or the amount that with the grid demand exceeds the generation threshold at time *t* under scenario *i* ($SD_{i,t}$) and the latter represents the power generated at time *t* (g_t). The grid demand is considered to calculate the weighting factor at each time slot. Thus, the time slots with higher grid demand is eligible for more weights. This could eliminate the power shortage effect by be biased to generate at time slots with higher grid demand. The time unit is one hour and the planning horizon *T* is one week (7 days=168 hours), with hour/time slot number 1 being 1:00 AM, Monday.

In the proposed model, generation threshold (THG_i) and pumping threshold (THP_i) are defined for each scenario *i*. When the grid demand ($GD_{i,t}$) is greater than the THG_i, the station is supposed to supply power to the grid. When the grid demand ($GD_{i,t}$) is less than the THP_i, the station could pump water for storage. The optimal hours of pumping and of generating during a weekly cycle can then be found.

The randomness in grid demand is denoted by a scenario *i*. Let $\varphi(i)$ be the corresponding probability of scenario $i \in I$, and $\sum_i \varphi(i)$ =1. A scenario defines the vector of outcomes of the parameters: grid demand ($GD_{i,t}$), station demand ($SD_{i,t}$), weighting factor ($\omega_{i,t}$), (THP_i) and (THG_i). Under certain conditions, the proposed model can be formulated in a closed form and hence an exact solution can be obtained. These conditions include the guarantee of: small problem size, and the stochastic parameters should be following the normal or uniform distributions. If the problem size gets larger, the closed form model is intractable. Furthermore, it is well known that the distribution of grid demand is close to a lognormal or normal distribution (Chikobvu and Sigauke, 2012). While there are computational benefits, due to the limitations of the closed form expression, this paper employs the SAA approach as a solution method. SAA (Shapiro *et al.* 2002) is a sampling based approach that can be applied to solve the PSSSP under grid demand uncertainty. Since we cannot directly optimize $\sum_{i=1}^{I}\sum_{t=1}^{T}\varphi(i)\ \cdot w_{i,t}\ \cdot z_{i,t}$, we instead maximize the expected value. While directly computing the expected value is not possible for most problems, it can be approximated through Monte Carlo sampling in some situations. The expected value, with sample size *I*, can be approximated by the average of the realizations:

$$\mathbb{E}_i\left[\sum_{t=1}^{T} w_{i,t}\ \cdot z_{i,t}\right] \approx \left[\frac{1}{I}\ \cdot \sum_{i=1}^{I}\sum_{t=1}^{T} w_{i,t}\ \cdot z_{i,t}\right]$$

Based on this approximation, the objective function is deterministic, and deterministic optimization methods can be used to solve the SPSSSP. Following, Table 1 summarizes the indices, parameters and decision variables used to formulate the problem mathematically.

Table 2. Notation summary

Notation	**Description**
Indices:	
t	Index of hourly time slot, *t = 1, . . . T*, where *T* is the horizon, which is 168 h (one-week time
i	Index of scenario, with sample size *I*.
Parameters:	
$\omega_{i,t}$	Weighting factor, which represents the importance of the profit versus the demand fulfilment.
$SD_{i,t}$	Station demand, shortage of energy or the amount that with the grid demand exceeds the
η	Efficiency of the pump-turbine cycle.
U_{MIN}, U_{MAX}	Energy storage capacity limits of the reservoir (GWh).
$U_{i,0}$, $U_{i,T}$	Initial and final levels in the reservoir (GWh).

M	Large enough number.
$GD_{i,t}$	Grid demand at time *t* under scenario *i* (GW).
THP_i	Threshold of grid demand to allow pumping (GW).
THG_i	Threshold of grid demand to allow generation (GW).
GP	Generation power for each pumped-storage unit (GW).
N	The total number of identical pumped-storage units.
Main decision variables:	
g_t	A real variable indicates the power generated at time *t* (GW).
p_t	A real variable indicates the power used for pumping at time *t* (GW).
x_t	Integer variables that indicate the number of units on generating mode at time period *t*.
y_t	Integer variables that indicate the number of units on pumping mode at time period *t*.
Auxiliary decision variables:	
$z_{i,t}$	A real indicator function for station's supply-demand disparity at time *t* under scenario *i*
$u_{i,t}$	Energy storage level of the upper reservoir at time *t* under scenario *i* (GWh).
$P_{i,t}^{Permissible}$, $G_{i,t}^{Permissible}$	Binary variables represent if it is permissible or allowable for pumping/generation at time slot *t* under scenario *i*.

The following mathematical model describes the SAA problem of the SPSSSP with sample size *I*.

The objective function is to:

$$Minimize \left[\frac{1}{I} \cdot \sum_{i=1}^{I}\sum_{t=1}^{T} w_{i,t} \cdot z_{i,t}\right] \qquad (1)$$

Subject to:

$$SD_{i,t} - g_t \leq z_{i,t} \qquad \forall i, \forall t \qquad (2)$$

$$g_t - SD_{i,t} \leq z_{i,t} \qquad \forall i, \forall t \qquad (3)$$

$$G_{i,t}^{Permissible} \cdot (GD_{i,t} - THG_i) \geq 0 \qquad \forall i, \forall t \qquad (4)$$

$$P_{i,t}^{Permissible} \cdot (THP_i - GD_{i,t}) \geq 0 \qquad \forall i, \forall t \qquad (5)$$

$$g_t \leq M \cdot G_{i,t}^{Permissible} \qquad \forall i, \forall t \qquad (6)$$

$$p_t \leq M \cdot P_{i,t}^{Permissible} \qquad \forall i, \forall t \qquad (7)$$

$$g_t = GP \cdot x_t \qquad \forall t \qquad (8)$$

$$p_t = GP \cdot y_t \qquad \forall t \qquad (9)$$

$$x_t \leq N \qquad \forall t \qquad (10)$$

$$y_t \leq N \qquad \forall t \qquad (11)$$

$$u_{i,t} = u_{i,t-1} - g_t + \eta \cdot p_t \qquad \forall i, \forall t \qquad (12)$$

$$U_{MIN} \leq u_{i,t} \leq U_{MAX} \qquad \forall i, \forall t \qquad (13)$$

$$U_{i,0} = U_{i,T} = U_{MAX} \qquad \forall i, \forall t \qquad (14)$$

$$P_{i,t}^{Permissible}, G_{i,t}^{Permissible} \in \{0,1\} \qquad \forall i, \forall t \qquad (15)$$

$$z_{i,t}, u_{i,t} \in \mathbb{R}^+$$

$$g_t, p_t \in \mathbb{R}^+ \qquad \forall t \qquad (16)$$

$$x_t, y_t \in \mathbb{Z}^+$$

The objective function (1) aims to minimize the expected value of the weighted sum of the disparity between the station demand and the power generated. It is assumed that the surplus and shortage of the power generated are both regarded as a disparity. Thus, the disparity ($z_{i,t}$) can be modeled using the absolute value of the difference between the station demand and the power generated, $z_{i,t} = |SD_{i,t} - g_t|$. A linear formulation for this function is represented in constraints (2-3).

Constraint 4 guarantees that generation mode is allowable at time slot *t* under scenario *i* only if the grid demand ($GD_{i,t}$) is greater than the generation threshold (THG_i). At that case, the binary variable $G_{i,t}^{Permissible}$ takes the value 1, otherwise $G_{i,t}^{Permissible}$ = 0. Similarly, constraint 5 guarantees that pumping mode is allowable at time slot *t* under scenario *i* only if the grid demand ($GD_{i,t}$) is lower than the pumping threshold (THP_i), where the binary variable $P_{i,t}^{Permissible}$ takes the value 1, otherwise $P_{i,t}^{Permissible}$ = 0. Constraints (6-7) guarantee that generation and pumping could occur during the allowable times only based on the values of $G_{i,t}^{Permissible}$ and $P_{i,t}^{Permissible}$, respectively. Constraints (8-9) determine the number of units scheduled in generation or pumping mode x_t and y_t, respectively. Where, constraints (10-11) guarantee that the number of units scheduled in generation or pumping mode at time *t* cannot exceed the total available number of units (*N*).

Constraints (12-14) are associated with pond or reservoir levels. Constraint 12 controls pond level dynamics and pond storage level over time. Consider the plant having an efficiency of η with an initial energy stored in the reservoir U_0. Assume that within a time period $t \in T$, the plant is scheduled to pump p_t (GW) or generate g_t (GW). Then, the stored/inflow energy in GWh at time t is ($\eta \cdot p_t$) and the consumed/outflow energy in GWh at time t is (g_t). Where, p_t and g_t is the amount of power used/consumed for pumping at time *t* and the amount of power generated at time *t*, respectively. Constraint 12 ensure that the pond level at time *t* under scenario *i* is within the minimum and maximum pond level limits. The initial and terminal pond levels are to be defined in constraint 14. It is assumed that the initial pond level is to be full. Also, the terminal pond level usually equals the initial pond level so that the pond is ready to be used for the next cycle. Finally, constraints (15-16) reflect the binary, integer and real properties of the decision variables.

3. Numerical results

The performance of the proposed stochastic MILP scheduling optimization model has been tested based on real data of Ingula pumped storage station in South Africa (Eskom[b]).

3.1. Case study data

The proposed model is applied to Ingula pumped-storage plant. The plant is formed by four 333 MW identical units (N=4) with cycle efficiency of 78% (Eskom[c]). The pumped storage scheme consists of an upper and a lower dam, each capable of holding approximately 22 million cubic meters of water which is equivalent to a maximum energy storage capacity 21 GWh ($U_{i,0} = U_{i,T} = U_{MAX} = 21.312\ GWh$) (Eskom[c]). Based on Chikobvu and Sigauke (2012) results, the daily peak electricity demand in South Africa has a stochastic trend with a normal distribution. The main two scenarios of the electricity demand in South Africa (winter and summer) are illustrated in Fig. 2. The summer (November to February) and winter periods (June to August) are characterized by different constraints. Winter is the period when the highest demand is experienced in the country, especially in the evening between 17h00 and 21h00. The summer demand is significantly lower than the winter demand, so most maintenance on generation plant is performed during this period. Even though demand is lower, it is more challenging to meet demand during this period than winter. In summer, the system is tight all day up to 10:00pm, due to the flat "Table Mountain" demand profile, and the shortfall generally is for up to ten hours or more as shown in Fig. 2.

3.2. Experimental results

The mathematical model describes the SAA problem of the SPSSSP is solved optimally with the commercial ILP solver LINGO 12.0 (LINDO Systems Inc.). All tests were run on an Intel Core i5 (2.6 GHz) with 4 GB of RAM, running under Windows 7. The proposed model is solved for three scenarios: "Winter" demand profile, "Summer" demand profile and "Robust" which considers both winter and summer demand profiles. Note that the computation times for all scenarios only a few minutes, the proposed model is therefore efficient to be used on a daily basis.

The pumped-storage plant generation deducted and pumping added, and reservoir level are shown in Fig. 3, 4 and 5 for Winter, Summer and Robust scenarios, respectively. Note that the capacity constraint is satisfied and the pumped-

storage plant generates more on week-days and pumps more on weekends. The role of the pumped-storage plant in smoothing peaks and filling valleys is obvious. The pumped-storage plant generates during day time (peak times) when grid demand is higher than the generation threshold and pumps at nights and during the weekend when grid demand is lower than the pumping threshold. Itis also observed that the reservoir is gradually depleted during the week-days and filled up on the weekend since demand in the weekdays are generally higher than those on the weekend. Also, pumping at night is to provide reserve so that the plant could commit along the week-days.

As an illustrative example, consider Winter Scenario, results shown in Fig. 3. During off-peak hours (at night and during the weekend), the grid demand is below the pumping threshold at 28 GW and the storage station operates at full pumping power. As the grid demand rises through the morning, the pumped storage station is switched off. When the grid demand reaches the generation threshold at 33 GW (for Winter Scenario), the storage station enters into service in generating mode and shaves the peaks off of the grid load. The proposed schedule shows that the weekly supply-demand disparity could be reduced by about 88% from 52 GW to 6.2 GW for the Winter Scenario.

Similarly, for Summer Scenario, results shown in Fig. 4. During off-peak hours (at night and during the weekend), the grid demand is below the pumping threshold at 28 GW and the storage station operates at full pumping power. As the grid demand rises through the morning, the pumped storage station is switched off. When the grid demand reaches the generation threshold at 30 GW (for Summer Scenario), the storage station enters into service in generating mode and shaves the peaks off of the grid load. Due to the flat "Table Mountain" demand profile during summer, and the shortfall generally is for up to ten hours or more as shown in Fig. 2, the pumped-storage plant has to be in generation mode for longer time during the day as shown in Fig. 4. The proposed schedule shows that the weekly supply-demand disparity could be reduced by about 82% from 60 GW to 10.4 GW for the Summer Scenario.

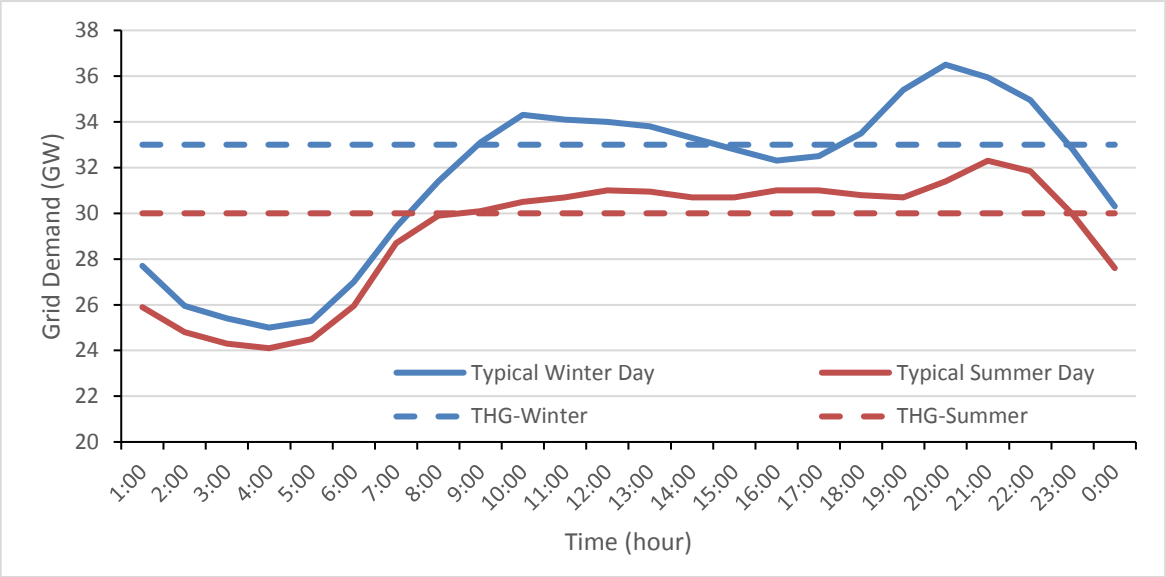

Fig. 2. Summer and winter demand profiles in South Africa

The Robust Scenario considers the grid demand for the Winter and Summer Scenarios simultaneously, and try to provide a one schedule that could fit for both scenarios and minimize average supply-demand disparity. Results for the Robust Scenario is shown in Fig. 5. The proposed schedule shows that the weekly supply-demand disparity (on average) could be reduced by about 82% from 56 GW to 10.2 GW for the Robust Scenario.

The obtained optimal weekly schedules for the pumped-storage plant under the three Scenarios are provided in Table II. Where numbers in bold "**1**, **2**, **3**, or **4**" represent the number of units scheduled on generating mode on a certain day and at a certain hour. Numbers inside circles "①, ②, ③ or ④" represent the number of units scheduled on pumping mode on a certain day and at a certain hour. A "0" represents staying offline. Between the three Scenarios, the pumping schedules do not change significantly, except that in Summer, where seven hours instead of six are scheduled at night

during the week-days. Furthermore, the scheduled pumping capacity is 151 unit-hour for the Summer Scenario and 138 unit-hour for each of the Winter and Robust Scenarios. So, for the Summer Scenario, the pumped-storage plant pumps and generates more on weekdays in comparison to the other two Scenarios. It is obvious that the pumped-storage plant generates for longer hours (almost 11 hours a day) during the day starting from 11:00 AM until 10:00 PM. This is expected because the effect of the flat "Table Mountain" demand profile during the summer.

3.3. Sensitivity Analysis

In order to investigate the effect of varying the pumping threshold has on the results, a sensitivity analysis was performed. In this analysis, the pumping threshold (*PTH*) is changed by a small amount and the obtained optimum solutions are compared in terms of the total supply-demand disparity ($\sum_t z_t$). The results of this analysis are shown in Table III. Generally, the lower pumping threshold the higher the disparity and shortfall. Rising the pumping threshold (*PTH*) to 30 is applicable only for the Winter case due date the conflict with the generation threshold for the other scenarios. A significant reduction in the shortfall is experienced when the pumping threshold (*PTH*) is raised to 30 GW. On contrast, lowering the pumping threshold (*PTH*) to 26 GW resulted in higher shortfall. The reason is that by lowering the pumping threshold (*PTH*) to 26 GW, the plant could pump only for four hours at night instead of six. This results in a lower reservoir levels that do not enable the plant to commit for generation during the week-days.

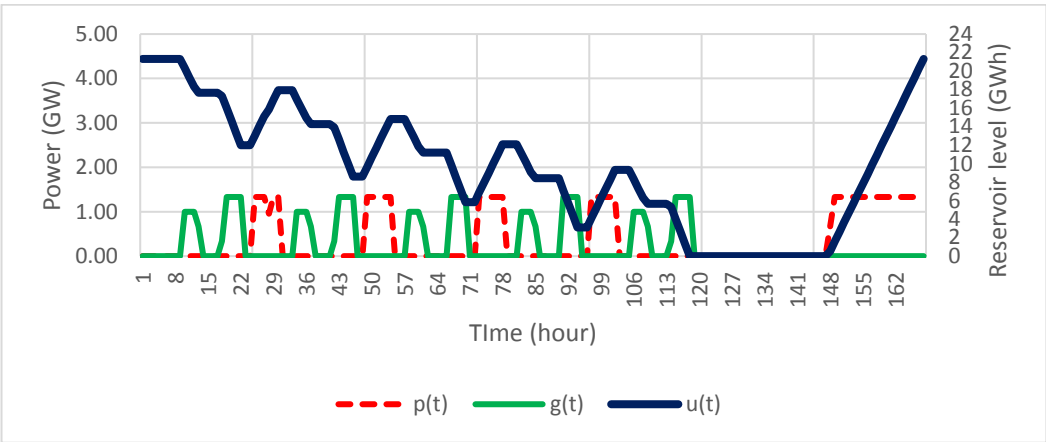

Fig. 3. Reservoir level and plant operations schedule through the week for Winter Scenario

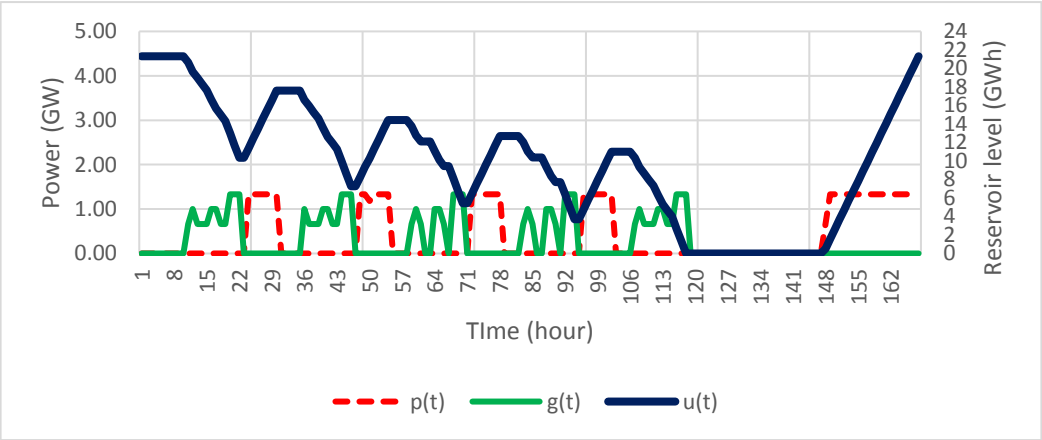

Fig. 4. Reservoir level and plant operations schedule through the week for Summer Scenario

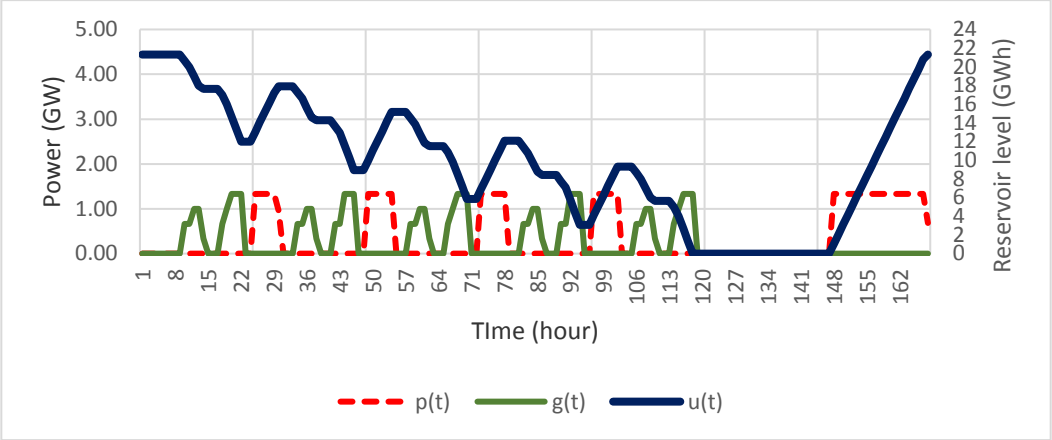

Fig. 5. Reservoir level and plant operations schedule through the week for Robust Scenario

Table 2. Optimal schedules for each of the three scenarios

	Winter							Summer							Robust						
Time (hour)	M	T	W	T	F	S	S	M	T	W	T	F	S	S	M	T	W	T	F	S	S
1	0	④	④	④	④	0	0	0	④	④	④	④	0	0	0	④	④	④	④	0	0
2	0	④	④	④	④	0	0	0	④	④	④	④	0	0	0	④	④	④	④	0	0
3	0	④	④	④	④	0	0	0	④	④	④	④	0	0	0	④	④	④	④	0	0
4	0	③	④	④	④	0	②	0	④	④	④	④	0	②	0	④	④	④	④	0	④
5	0	④	④	④	④	0	④	0	④	④	④	④	0	④	0	④	④	④	④	0	④
6	0	④	④	④	④	0	④	0	④	④	④	④	0	④	0	③	④	④	④	0	④
7	0	0	0	0	0	0	④	0	0	0	0	0	0	④	0	0	0	0	0	0	④
8	0	0	0	0	0	0	④	0	0	0	0	0	0	④	0	0	0	0	0	0	④
9	0	0	0	0	0	0	④	0	0	0	0	0	0	④	0	0	0	0	0	0	④
10	**3**	**3**	**3**	**3**	**3**	0	④	0	0	0	0	0	0	④	**2**	**2**	**2**	**2**	**2**	0	④
11	**3**	**3**	**3**	**3**	**3**	0	④	**2**	0	**2**	**2**	**2**	0	④	**2**	**2**	**2**	**2**	**2**	0	④
12	**3**	**3**	**3**	**3**	**3**	0	④	**3**	**3**	**3**	**3**	**3**	0	④	**3**	**3**	**3**	**3**	**3**	0	④
13	**2**	**2**	**2**	**2**	**2**	0	④	**2**	**2**	**2**	**2**	**2**	0	④	**3**	**3**	**3**	**3**	**3**	0	④
14	0	0	0	0	0	0	④	**2**	**2**	0	0	**2**	0	④	**1**	**1**	**1**	**1**	**1**	0	④
15	0	0	0	0	0	0	④	**2**	**2**	0	0	**2**	0	④	0	0	0	0	0	0	④
16	0	0	0	0	0	0	④	**3**	**3**	**3**	**3**	**3**	0	④	0	0	0	0	0	0	④
17	0	0	0	0	0	0	④	**3**	**3**	**3**	**3**	**3**	0	④	0	0	0	0	0	0	④
18	**1**	**1**	0	0	**1**	0	④	**2**	**2**	**2**	**2**	**2**	0	④	**2**	**2**	**2**	**2**	**2**	0	④
19	**4**	**4**	**4**	**4**	**4**	0	④	**2**	**2**	0	0	**2**	0	④	**3**	**2**	**3**	**2**	**3**	0	④
20	**4**	**4**	**4**	**4**	**4**	0	④	**4**	**4**	**4**	**4**	**4**	0	④	**4**	**4**	**4**	**4**	**4**	0	④
21	**4**	**4**	**4**	**4**	**4**	0	④	**4**	**4**	**4**	**4**	**4**	0	④	**4**	**4**	**4**	**4**	**4**	0	④
22	**4**	**4**	**4**	**4**	**4**	0	④	**4**	**4**	**4**	**4**	**4**	0	④	**4**	**4**	**4**	**4**	**4**	0	④
23	0	0	0	0	0	0	④	0	0	0	0	0	0	④	0	0	0	0	0	0	④
24	0	0	0	0	0	0	④	④	④	④	④	0	0	④	0	0	0	0	0	0	②

Table 1. Supply-demand disparity under two pumping threshold (PTH) for each of the three scenarios

The pumping threshold (*PTH*)	**Winter**	**Summer**	**Robust**
30	2.8	NA	NA
28 (Base case)	6.2	10.4	10.2
26	14.5	14.8	14.5

4. Conclusion

This paper addressed the SPSSSP while incorporating grid demand uncertainty aspect. The objective of this study is to generate an optimal PSS schedule that determines the number of units to be hourly scheduled in generation or pumping mode. An MILP model based on the sample average approximation method is proposed with the objective of minimizing the weighted score of the supply-demand disparity. A case study, based on Ingula pumped-storage station in South Africa, showed that the proposed schedule could reduce the weekly supply-demand disparity by about 88%, 82% and 82% for the Winter, Summer and Robust Scenarios, respectively. Furthermore, the scheduled pumping capacity is more in the Summer Scenario than in the Winter and Robust Scenarios. So, for the Summer Scenario, the pumped-storage plant pumps and generates more on weekdays in comparison to the other two Scenarios. Also, during the summer, it is found that the pumped-storage plant generates for longer hours during the day. This is expected because the effect of the flat "Table Mountain" demand profile during the summer.

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Biographies

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