Tariff structure selection for optimal electricity cost savings on a process plant

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Abstract

South Africa's electricity grid is currently under strain due to the high demand of electricity. This strain on the grid has resulted in the increase of electricity costs that has put financial pressure on consumers. In addition to this, consumers that are supplied through municipalities have to cope with additional service costs of up to 20%. Process plants are among the highest energy consumers and are therefore vulnerable to these cost increases.

Eskom introduced different electricity tariff structures that are designed to allow consumers to be cost reflective and to decrease the country's peak profile. In addition to this, the Demand Side Management (DSM) programme was implemented to allow consumers to manage their load profile. A clear understanding of a plant operation is necessary before choosing a tariff structure. This study analysed the integration of power consumption with production in order to decide on the tariff structure and load management profile that resulted in the best electricity cost savings.

A simulation model was used to integrate plant operational constraints with various tariff structures. The model then produced and optimised load profile and cost savings. The model was used to simulated cost savings on two case studies. The verified annual cost savings amounted to R3.2-million, which is equivalent to 13% of the electricity costs. This presents opportunities for significant cost savings if the right tariff structure is matched to the specific electricity usage trends of the consumer.

Keywords: Tariff structures, Process plants, Load shifting.

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Abbreviations

AS	Affordability Subsidy
AUC	Annual Utilised Capacity
CPI	Consumer Price Index
DMP	Demand Market Participation
DSM	Demand Side Management
ED	Energy Demand
ERNS	Electrification and Rural Subsidy

HO	Hourly Output
IDM	Integrated Demand Management
LSH	Load Shift Hours
MH	Maintenance Hours
MPC	Monthly Production Capacity
NA	Network Access
ND	Network Demand
NERSA	National Energy Regulator of South Africa
NMD	Notified Maximum Demand
OCGT	Open Cycle Gas Turbine
OH	Operating Hours
POD	Point of Delivery
RS	Reliability Service
SCADA	Supervisory Control and Database Acquisition
TN	Transmission Network
TOU	Time-Of-Use
ULVS	Urban Low Voltage Subsidy
VRM	Vertical Roller Mill
WEPS	Wholesale Electricity Pricing System

Nomenclature

Symbol	***Description***	***Unit***
AV	Availability factor	
CU	Capacity utilisation	%
E	Electricity consumption	kWh
Ms	Scheduled maintenance factor	
PV	Production volume	tonnes
R	Reliability factor	
SEC	Specific energy consumption	kWh/tonne
UD	Utilised demand	kVA

Chapter 1: Introduction

1.1. Background

1.1.1. Electrical power consumption and tariffs in South Africa

The South African economy experienced rapid growth in the years of 2000 to 2007. This growth in the economy has been the main contributor to the increase of electricity consumption in the country. With the country's demand of electricity increasing, Eskom's electricity supply was put under strain. Eskom's electricity reserve margin decreased from 25% in the year 2000 to 8% in the year 2007 [1].

Eskom introduced load shedding as a result of the electricity demand exceeding the generation capacity [2]. To ensure that the grid met the electricity demand, Eskom embarked on expansion projects to increase their power generation capacity. These expansion projects will increase Eskom's generation capacity by 17 384 MW by 2019/20 [3].

In order to be able to fund the expansion projects, Eskom applied for annual tariff increases with the National Energy Regulator of South Africa (NERSA). The price increases were granted and electricity prices have been increasing significantly since 2008 [4]. Figure 1.1 shows the average tariff increase versus the consumer price index (CPI) for the years of 1995 to 2015 [5]. In the figure, it can be seen that from 2008 electricity prices have been increasing at a much higher rate than the CPI.

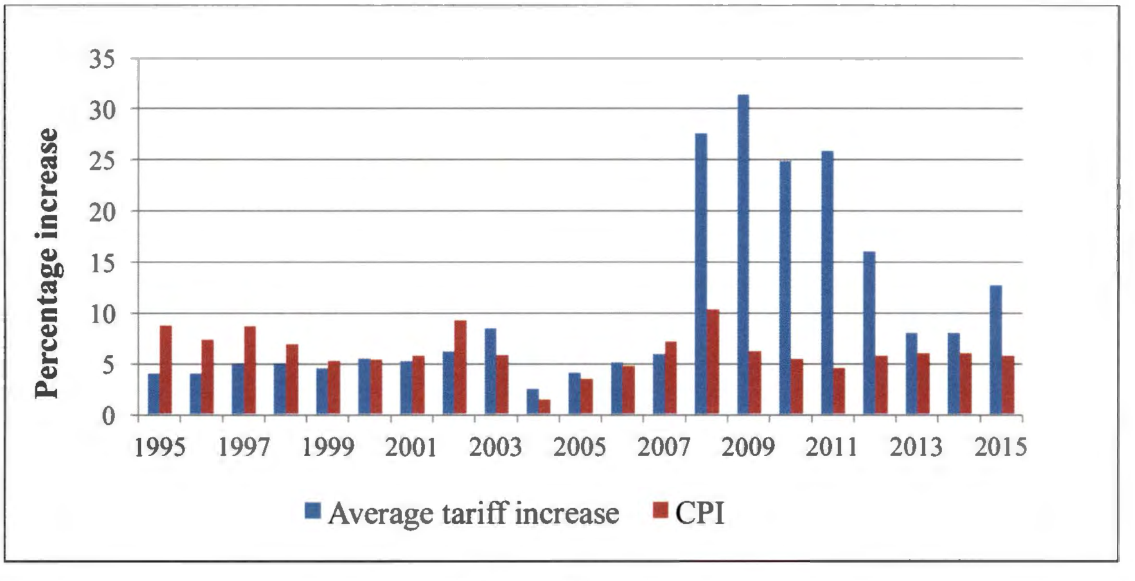

Figure 1.1: Eskom tariff increase vs. CPI

Many electricity consumers are not direct Eskom customers; these consumers are supplied with electricity by various municipalities. Municipalities add a mark-up on the electricity tariff prices, with some municipality mark-ups being as high as 20% [6]. Many municipalities increase their electricity tariffs outside of the regulations stipulated by NERSA, thus putting a big financial burden on electricity consumers [6].

Eskom's total electricity demand profile shows two periods of high demand, the morning peak (07:00-10:00) and the evening peak (17:00-21:00) [7]. These peak periods put strain on Eskom's reserve margin. These high demand periods result in Eskom utilising its open cycle gas turbine (OCGT) generation facilities as a means of meeting the high demand of electricity. Eskom tries to minimise the usage of the OCGT due to the high operational expenses associated with it. Figure 1.2 shows Eskom's 2008 electricity demand profile, the two peak periods are shown for a summer day, a winter day and a peak day in 2008 [7].

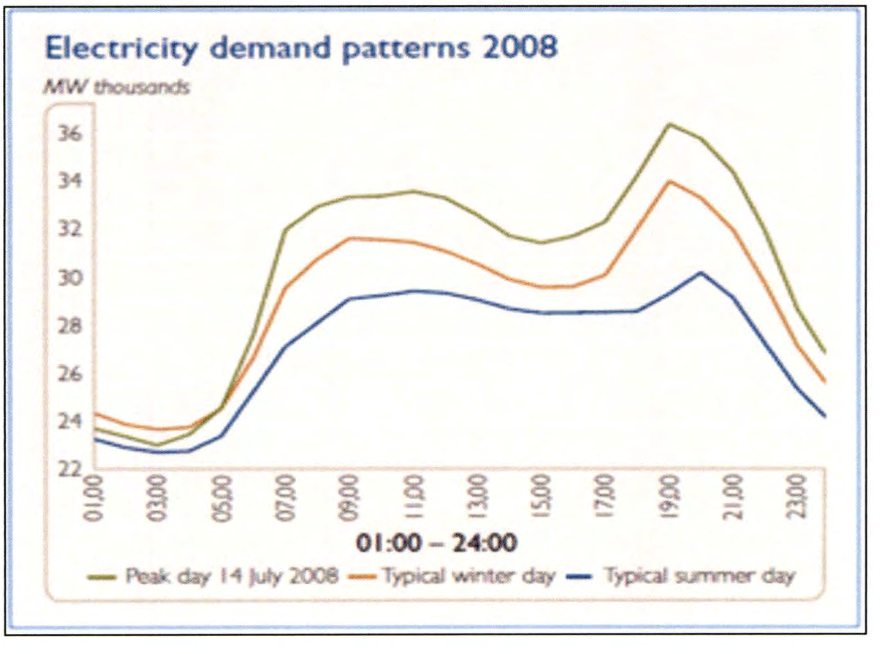

Figure 1.2: Eskom electricity demand pattern 2008

In order to help consumers minimise the country's peak electricity demand, Eskom has introduced different tariff structures. These tariff structures are meant to reflect the cost of generating and supplying electricity to consumers at different time periods. There are various tariff structures that are designed for different electricity consumption conditions.

Most industrial electricity consumers in South Africa are on a Time-of-Use (TOU) tariff structure. With TOU tariffs, the cost of electricity is charged differently depending on what time the electricity was consumed. Electricity consumption during the peak periods is charged at higher rate as a way of encouraging industrial electricity consumers to use electricity during the low-demand periods. Eskom's TOU tariffs include tariffs such as Megaflex and Miniflex.

1.1.2. Process plants

Process plants are plants that process raw materials into products in industries such as cement, gold, steel, fertilizer and food processing. Process plants vary depending on the raw material being processed and the product being produced. With process plants being used in the production of so many different products, they play an integral role in the manufacturing industry in South Africa.

The plants consist of several components such as storage and processing components, as well as piping systems that carry the material from one storage or processing component to the other. Processing components include equipment such as mills, crushers, separators, evaporators and kilns [8]. Storage components include silos, stockpiles and bins. Figure 1.3 shows a cement process plant layout; the process equipment is highlighted in red and the storage components are highlighted in brown [9].

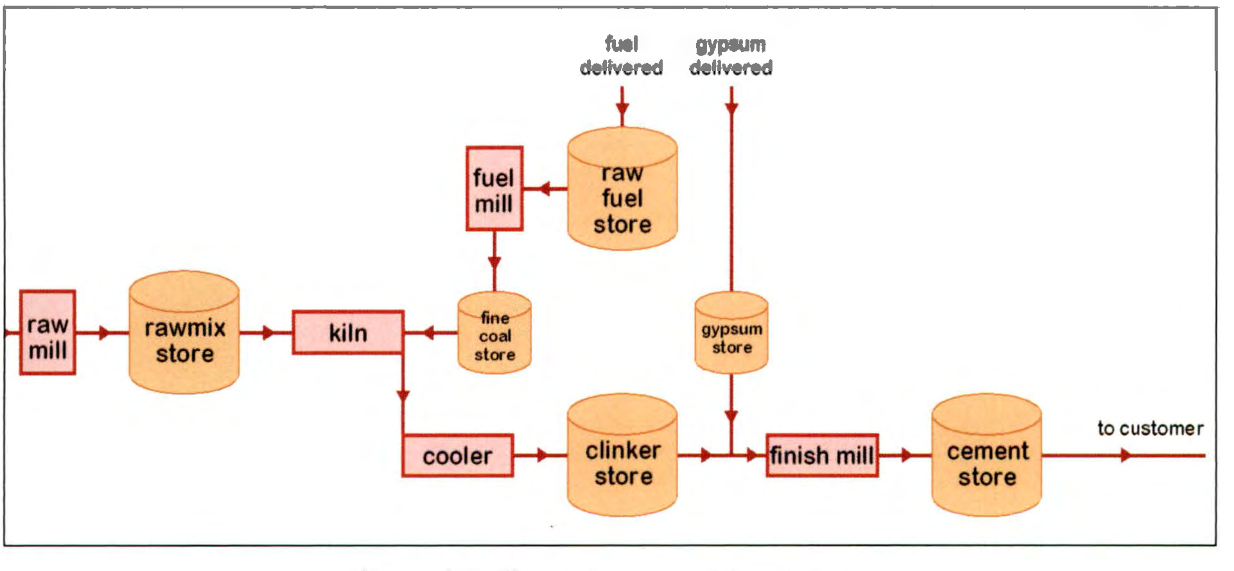

Figure 1.3: Cement process plant layout

Process plants have very energy-intensive equipment and therefore consume large amounts of electricity. In some plants, the energy demand (ED) of the intensive equipment can be up to 81% of the plant's total electricity demand [10]. This high energy use results in high electricity costs. Electricity costs can amount to 15% of the total operational costs of the plant [11].

1.1.3. DSM and load management initiative

In 2004, Eskom introduced a Demand Side Management (DSM) programme in the commercial and industrial sectors [12]. This programme was aimed at improving the energy efficiency and load management in South Africa. DSM projects include load management and decreasing the overall energy consumption through energy efficiency. A number of DSM projects have already been completed on process plants in industries such as gold and steel [13], [14].

Energy efficiency is the use of less energy to provide the same service or product. It is the reduction of the overall electricity consumption profile. This reduction of the consumption of electricity leads to electricity cost savings [15]. These cost savings are even more significant during peak periods and the winter season when TOU tariff costs are high.

Load management is based on the reduction of energy consumption during peak periods. Electrical load is shifted from expensive high-demand periods to less expensive low-demand TOU periods [16]. Load shifting helps in reducing the pressure that the Eskom grid experiences during peak periods and also helps electricity consumers reduce their electricity costs. Load management is often easy for electricity consumers to implement due to the low capital costs associated with it [17].

Due to the high electricity usage in process plants, and the large cost associated with the usage, process plants can benefit from DSM initiatives. This high energy use, and thus high electricity costs, can be a motivating factor for process plants to reduce electricity costs. Since the electrical utilisation of the process plants is usually below 100 %, process plants are often able to implement load management and therefore realise electricity cost savings [18].

1.2. Problem statement

There are various tariff structures that are designed for different industrial electricity consumers. Electricity consumers need to select a tariff structure that best represents the process plant's power consumption profile. However, some consumers have little knowledge regarding tariff structure and may therefore have difficulty in choosing the correct tariff structure for their process plant. This lack of knowledge may lead to consumers losing out on the opportunity to save on electricity consumption costs.

The implementation of DSM energy management projects on various process plants has resulted in electricity cost savings. However, no tariff structure selection investigation was done in these projects; the TOU tariff Megaflex was assumed to be the best tariff structure. The absence of an investigation of other tariff structures could have resulted in less than optimal cost savings.

1.3. Research objective

The objectives of the study are to design a calculation method that will enable process plants to compare the cost of electricity for different tariff structures. The calculation method will help process plants in determining which tariff structure has the lowest electricity costs. These cost calculations will be investigated for various production conditions where load management is implemented and conditions where no load management takes place. This will help process plants know how the electricity costs of each tariff structure are affected by changes in production. The process plants will thus be able to choose the best tariff structure.

1.4. Scope of study

This research is based on two process plants in South Africa. The first process plant is a slagment manufacturing plant and the second a cement manufacturing plant. The study will thus focus on cement and slag milling plants. The calculations will be concentrated on the energy-intensive equipment on the plant. The tariff structures investigated are those of Eskom and other municipalities in South Africa.

1.5. Overview of dissertation

Chapter 2

Chapter 2 provides the literature study looking at the cost saving opportunities on process plants. The cement and slagment manufacturing processes are discussed in detail and various electricity tariff structures for industrial electricity consumers are investigated. The DSM energy management in process plants is also discussed.

Chapter 3

A method that will assist process plants in selecting a tariff structure that will result in optimal cost savings is described. The method takes into account the plant operational constraints and the possible tariff structure options that a plant can select from. The inputs of the method and simulation of the electricity costs are described in detail.

Chapter 4

The two case studies are discussed in this chapter. The calculation method in Chapter 3 is used to forecast the electricity cost savings. The actual cost savings achieved after the implementation of the calculation methodology will be presented. These cost savings will be compared to the forecasted cost savings to determine if the calculation method was accurate in forecasting the electricity cost savings.

Chapter 5

A conclusion of the research objectives and the results obtained are discussed.

Chapter 2: Electricity cost saving opportunities in process plants

2.1. Overview

In this chapter a literature study on the electricity cost saving opportunities in cement manufacturing and slag milling plants is presented. The chapter starts with an overview of the cement manufacturing and slag milling processes. The Eskom and municipality tariffs for industrial electricity consumers are then discussed. The focus then shifts to electricity cost saving opportunities on energy-intensive equipment used in the cement manufacturing and slag milling processes.

2.2. Cement manufacturing process

2.2.1. Raw material preparation

Cement can be manufactured through either the wet or dry production processes, the dry process is 30% more energy efficient than the wet process [19], [20]. Cement production in South Arica is only done through the dry process. Electricity and coal are the two major sources of energy on the cement plants in South Africa [19]. Figure 2.1 shows the dry cement manufacturing process [8], [17]. Cement manufacturing consists of five major processes, i.e. raw material preparation, clinker production, finishing milling, packing and dispatching.

The primary ingredient in cement is limestone. Limestone is mined in quarries that are usually situated close to the cement manufacturing plant. The limestone reefs are blasted and broken down into large rocks. The rocks are then broken down by crushers into smaller pieces of about 50 mm. The crushed limestone is then homogenised to ensure efficient combustion in the kiln [17], [21]. The homogenised limestone is then blended with other raw materials such as iron ore and clay and stored in blending silos.

The homogenised raw material is then fed into the raw mills. The raw mill grinds the raw material mixture into a fine powder. The raw mills used on most South African cement plants are either ball mills or vertical roller mills (VRMs). Ball mills consist of a rotating horizontal cylinder partly filled with steel balls [22]. The VRM has a roller that grinds the raw material on a rotating table [17]. The ground material is called the raw meal and is stored in silos.

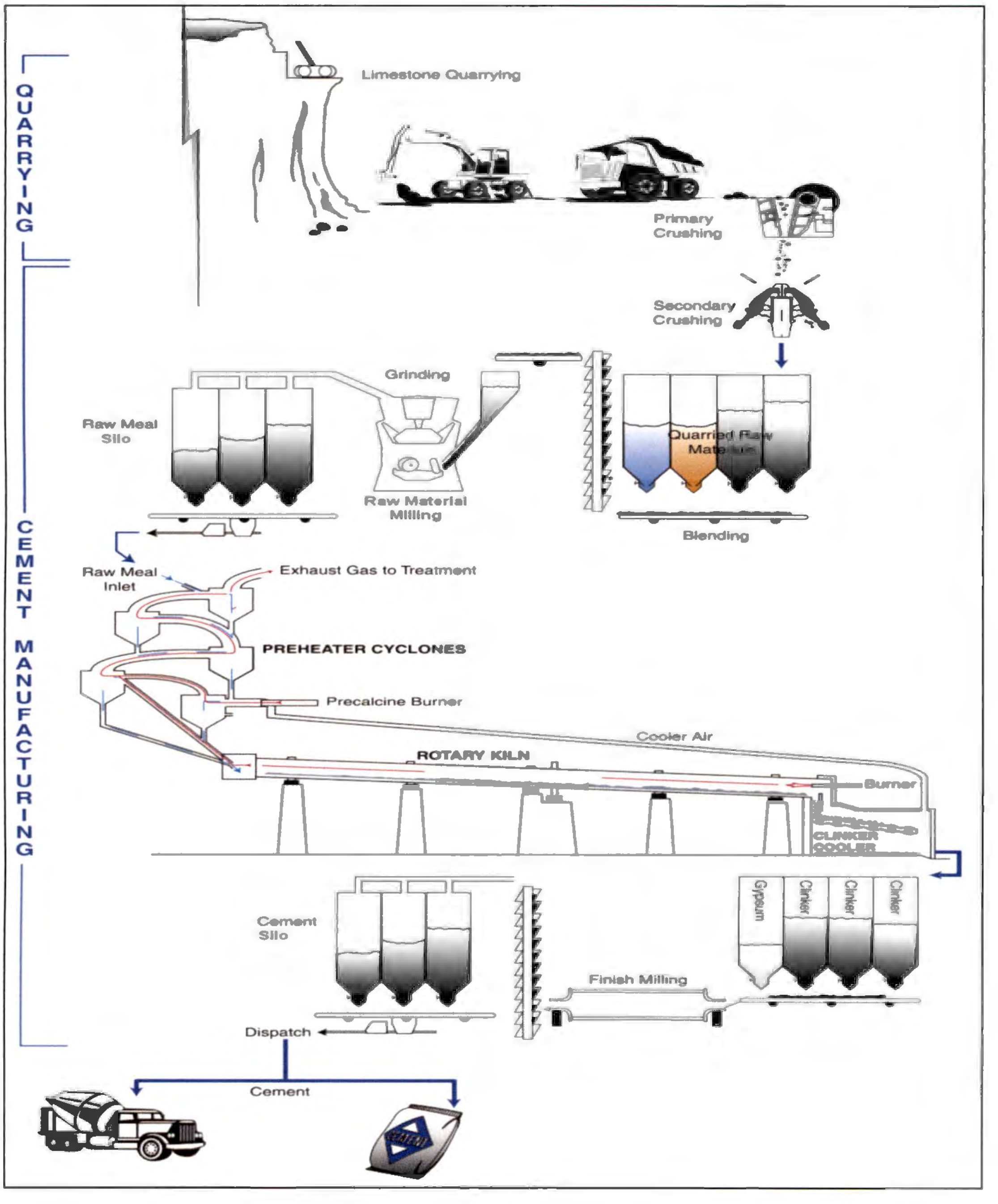

Figure 2.1: Cement manufacturing process

Figure 2.2 shows a ball mill [23]. As the mill rotates, the steel balls fall back onto the cylinder and grind the raw material. The mill shown in the figure collects the finished product at the bottom and the dust at the top. Some ball mills can have an inlet for the raw material at both ends of the mill.

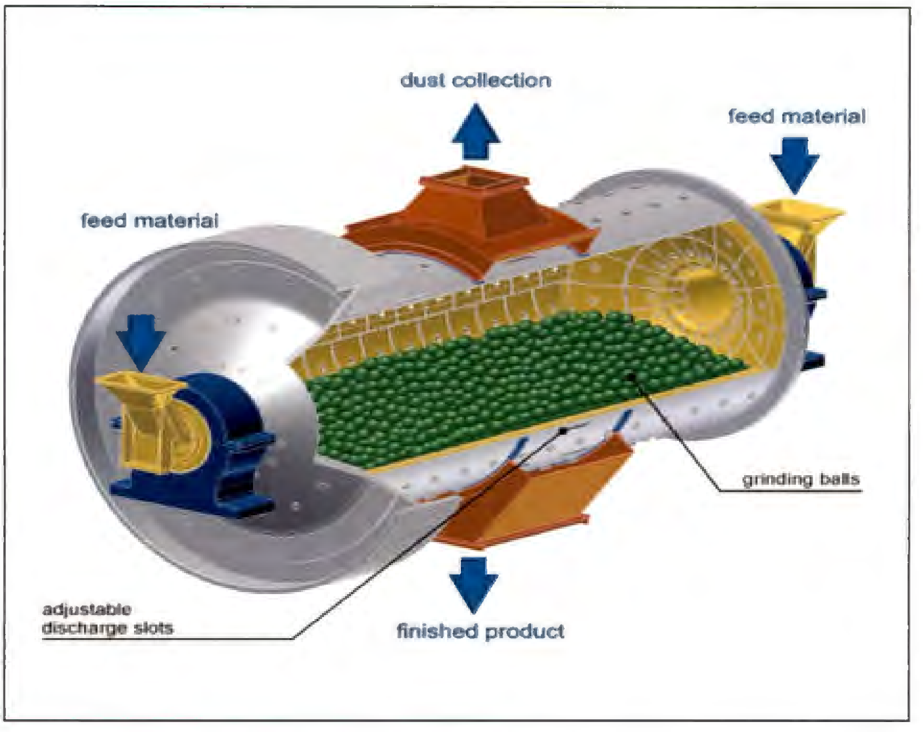

Figure 2.2: Ball mill

Figure 2.3 shows a VRM [24]. The raw material comes in through the inlet chute, and the fine product exits the mill via the outlet duct. The reject cone is a classifier that returns the particles that are too large back to the grinding table for more grinding. The particles that meet the size specifications pass through the reject cone and exit the mill.

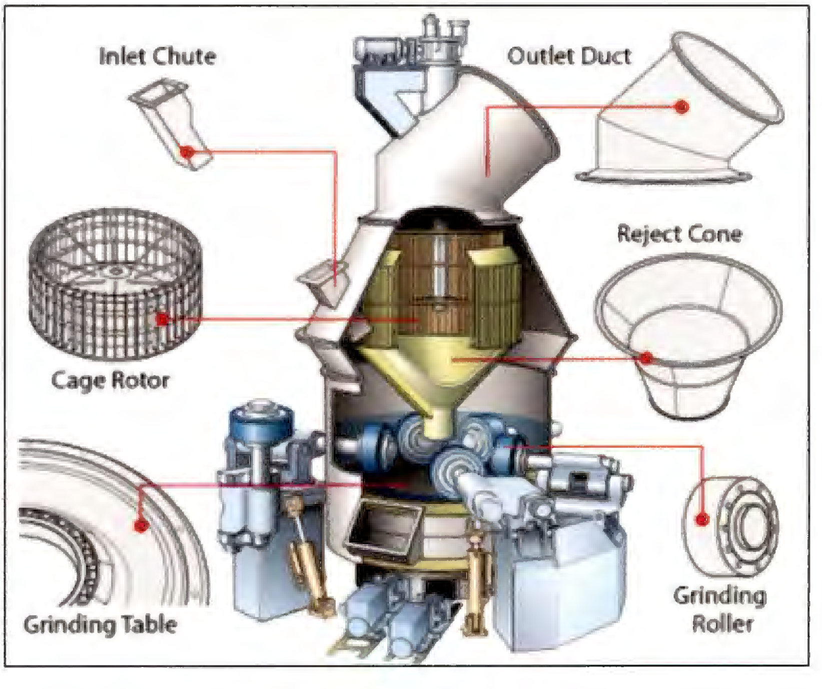

Figure 2.3: Vertical roller mill

The raw mills use electricity as a source of energy. They have energy intensive motors and auxiliaries such as fans and classifiers motors that also consume energy. The rotary movement of the classifiers and the wind blown by the fans separate the fine cement particles from the larger cement particles [25]. VRMs are more energy efficient but are more difficult to operate and maintain [26].

2.2.2. Clinker production

The raw meal is preheated to 800 ˚C to remove any moisture that may be present in the mixture before it is fed to the kiln [17]. It is preheated by hot exhaust gases from the kiln in gas suspension cyclones as shown in Figure 2.4 [27]. Heat transfer takes place between the hot gases and raw meal due to the centrifugal forces that are created in the cyclones.

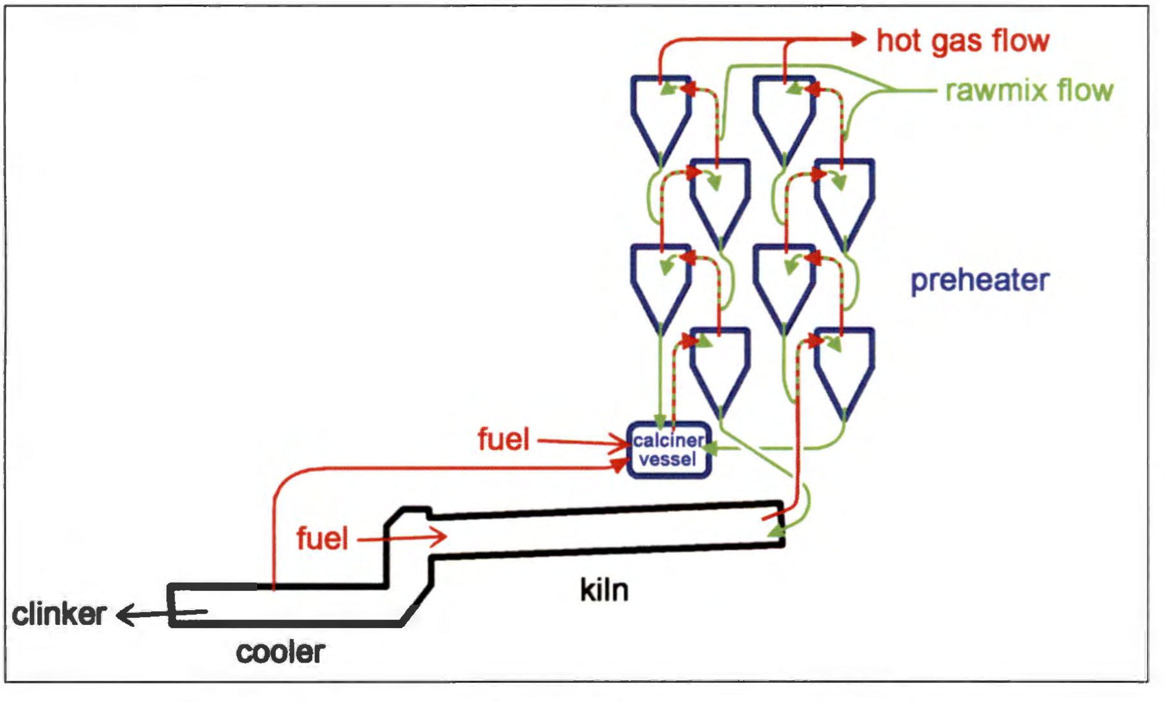

Figure 2.4: Preheating of raw meal in gas suspension cyclones

The preheated raw meal is then fed into the kiln. The kiln is a fire-brick coated steel cylinder that is tilted slightly downwards. The raw meal gradually moves along the kiln where it is exposed to high temperatures. These high temperatures cause chemical reactions to occur between the limestone and the other raw materials; these chemical reactions lead to the formation of clinker. Clinker is a dark grey material that is produced by heating limestone to temperatures of 1400-1500 ˚C; clinker is the raw material for cement [28].

When the clinker exits the kiln, it enters the coolers. The clinker is cooled by ambient air that passes through the coolers to the kiln to be used as combustion air. This air passed through the coolers can also be used in the preheaters to heat the raw meal. The most common types of coolers are: reciprocating grate, planetary and rotary coolers. The coolers decrease the temperature of the clinker from about 1 100 °C to 93 °C [29].

Most kilns use coal as a source of energy while alternative fuels such as waste vehicle tyres and natural gases are also used [29]. The coal is first pulverised into a fine powder in the coal mill and then dried to remove any moisture before it is used as fuel. The coal is fed into the kiln where the hot gases from the kiln ignite the coal. The coal provides heat of up to 1400 °C [17].

The clinker production is the slowest process in the cement production process; the kiln can therefore determine the production capacity of the plant. Due to this slow rate, kilns often operate for 24 hours a day and are only switched off for maintenance [17].

2.2.3. Finishing milling

The cooled clinker is mixed with additives such fly ash and gypsum before it is milled in the cement mills. The finishing mills grind the clinker and additives to fine cement. The classifier in the mill plays an important role in ensuring that the cement particles are the correct size. The ground cement is blown by hot air in the classifier. Fine particles are blown through the classifier, whilst bigger particles are returned to the mill for more grinding [18].

The particle size of the cement determines the setting time. The finer the particles, the quicker the cement settles [18]. Finer particles require longer milling periods and therefore require more electricity. Different types of cement can be produced depending on what additives are added and what the particle size of the cement is. The cement from the finishing mills is stored in cement silos.

2.2.4. Packing and dispatch

The cement is packed in bags and dispatched to distributors by road or railway [22]. Some of the cement is loaded in bulk and transported directly to customers. It is important that plants monitor production and cement storage levels to ensure that the dispatching of cement is not interrupted.

2.2.5. Electricity consumption in a cement plant

Electricity is the main source of energy for the majority of equipment on a cement plant. A cement plant therefore consumes a large amount of electricity. The mills are the highest electricity consuming equipment in the cement manufacturing process. The mills also have auxiliaries such as fans and separators that add to their electricity consumption. Though the kiln uses a lot of energy, that source of energy is supplied by coal.

Figure 2.5 shows the energy-intensive equipment on a cement plant [18], [21]. The equipment highlighted in red consumes large amounts of electrical energy, and the equipment highlighted in yellow are high thermal energy consumers.

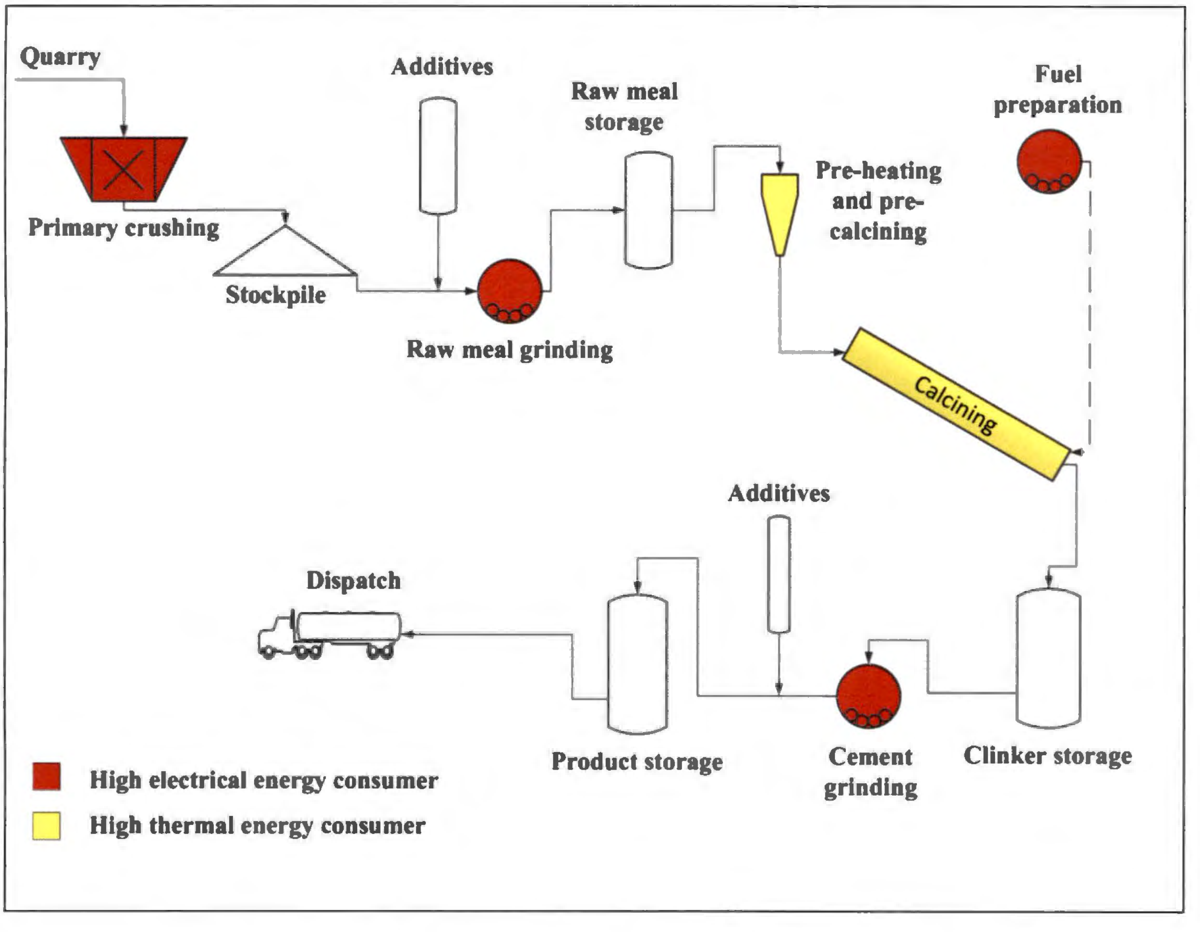

Figure 2.5: Energy-intensive equipment on a cement plant

Figure 2.6 shows the distribution of electricity consumption on a cement plant [19]. From this figure it can be seen that mills consume the highest amount of electrical energy. The preheater of the kiln also consumes a significant amount of electrical energy. This is because the hot gas that heats up the raw material is driven by fans that use electricity as a source of energy.

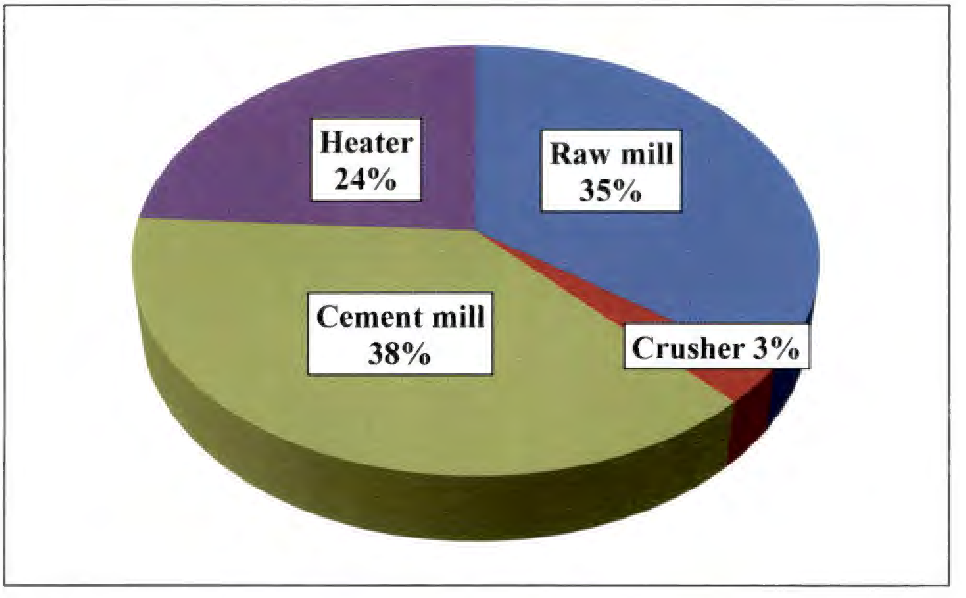

Figure 2.6: Electricity consumption distribution on a cement plant

2.3. Slag milling

Slag is a by-product that is produced during the separation of impurities from molten iron or steel in steel making furnaces. The slag is a solution of silicates and oxides that solidifies when cooled. There are various types of slag that can be produced; slag such as furnace slag, raker slag, ladle slag and pit slag are common types of slag. The type of slag produced is dependent on the grade of steel or iron that is being manufactured [30].

Slag is used in the cement industry as a supplementary material; it is blended with clinker. Slag is used to increase strength, improve resistance to chemical attack, reduce permeability and inhibit corrosion in cement [31]. Slag can also be used separately as a cementing component.

Before the slag is used, it firstly needs to be ground to a fine powder at a mill. Slag can contain as much as 30% of water; therefore it often needs to be dried before grinding occurs. The slag can be ground together with clinker at a cement manufacturing plant or the grinding can be done separately at a slag milling plant [32]. Slag requires 30 – 50% more energy than clinker during grinding due to the glassy structure that makes it difficult to grind [32].

2.4. Electricity tariff structures

2.4.1. Tariff structures for industrial electricity consumers

Eskom has designed different electricity tariff structures that accommodate various energy consumers. These tariff structures are meant to reflect the cost of supplying electricity during different time periods [33]. Tariff structures allow energy consumers to be billed on their specific energy usage profile. To ensure the financial viability of the utility, the full recovery of the cost of supplying electricity is essential. Therefore capital, operational and maintenance costs of the power utility are important in the design of tariff structures.

In addition to cost reflectivity and revenue recovery, tariff structures have other objectives that need to be met. These objectives include aspects such as affordability of the tariffs and the environmental impact caused by the production and distribution of electricity. NERSA requires that tariff structures meet the objectives of all stake holders involved, i.e. the consumer, the utility, and the state. Figure 2.7 shows the summary of the consumer, utility and state objectives that tariff structures should achieve [34].

TOU tariff structures were introduced in the late 1990s to reflect the cost of generating electricity during the peak periods [35]. During the peak periods, electricity is charged at a higher rate as a means of encouraging industrial electricity consumers to use electricity during the lower demand periods. Industrial electricity consumers that are supplied by Eskom are restricted to the TOU tariff structures Megaflex, Miniflex, Nightsave and WEPS [36]. WEPS is an acronym for wholesale electricity pricing system.

Municipality tariff structures vary from one municipality to another. Some municipalities have tariff structures that are similar to the Eskom tariff structures, and some do not. Some municipalities have Megaflex and Nightsave available for the industrial electricity consumer under those municipalities [6].

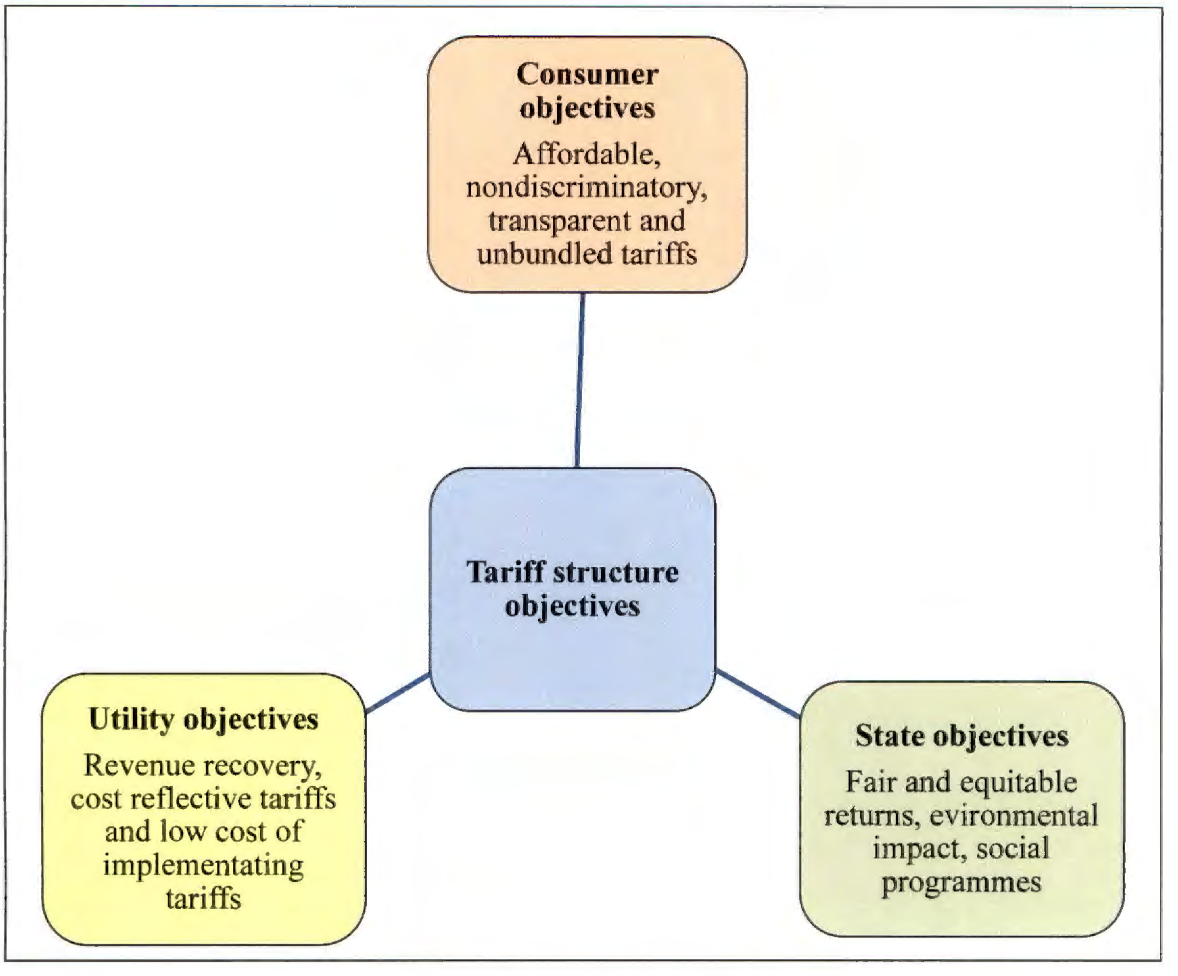

Figure 2.7: Tariff structure objectives

Each tariff structure caters for a specific range of notified maximum demand (NMD). The NMD is the contracted maximum demand notified by the consumer in writing and accepted by Eskom [37]. Table 2.1 shows the tariff structures and their corresponding NMD requirements [36].

Each of the tariff structures has a non-local tariff and a local tariff. The local authority tariff is tariff applicable to municipal bulk points of supply, while non-local authority tariff applies to Eskom's direct customers [38]. The charges in each non-local and local tariff structure are categorised according to the transmission zone and the voltage of the supply. Transmission zone relates to the location of the plant and whether the plant is rural or urban [36]. The voltage of supply is related to the cost of distributing electricity to the plant [37]. Table 2.2 shows the transmission zone and voltage categories [36].

Table 2.1: Eskom tariff structures and their corresponding NMDs

Tariff structure	**NMD**
Nightsave Large	NMD > 1 MVA
Nightsave Small	25 kVA ≤ NMD ≤ 1 MVA
Megaflex	NMD > 1 MVA
Miniflex	25 kVA ≤ NMD ≤ 5 MVA
WEPS	NMD > 1 MVA

WEPS is the wholesale tariff structure that has the same structure and rates as Megaflex [38]. It is designed for customers with a minimum annual consumption of 100 GWh. WEPS is a cost reflective tariff structure that has costs in the most unbundled format. The WEPS tariff consists of components such as energy charges, reliability service charges and administration charges.

The majority of the cement process plants in South Africa that are Eskom customers are either on the Megaflex or Nightsave tariff structures. This section will thus focus on these two tariff structures.

2.4.2. Megaflex

Megaflex is based on TOU active energy (kWh) charges and is suitable for cement plants that do not have a high load factor [36]. Load factor is the ratio of the average load in kWh used to the maximum load at any specific time [39]. Load factor gives an indication of whether a plant is able to shift load or not; cement plants that do not have a high load factor are able to shift load. Megaflex is therefore suitable for plants that are able to shift load.

Table 2.2: Eskom transmission zone and voltage categories

Transmission zone	**Voltage**
≤ 300 km	< 500 V
	≥ 500 V and < 66 kV
	≥ 66 kV and ≤ 132 kV
	> 132 kV
> 300 km and ≤ 600 km	< 500 V
	≥ 500 V and < 66 kV
	≥ 66 kV and ≤ 132 kV
	> 132 kV
> 600 km and ≤ 900 km	< 500 V
	≥ 500 V and < 66 kV
	≥ 66 kV and ≤ 132 kV
	> 132 kV
> 900 km	< 500 V
	≥ 500 V and < 66 kV
	≥ 66 kV and ≤ 132 kV
	> 132 kV

Megaflex has peak, standard and off-peak TOU periods [36]. The peak periods are hours in the day where Eskom experiences high demand in electricity throughout the country. The demand for electricity is lower during the standard periods and the lowest during the off-peak periods.

The electricity charges are the highest during the peak periods and the lowest during the off-peak periods. This encourages plants to shift their load from peak periods to the off-peak and standard periods. Figure 2.8 shows the Megaflex TOU periods during the low-demand season (September-May) and Figure 2.9 shows the Megaflex TOU periods during the high-demand season (June-August) [36].

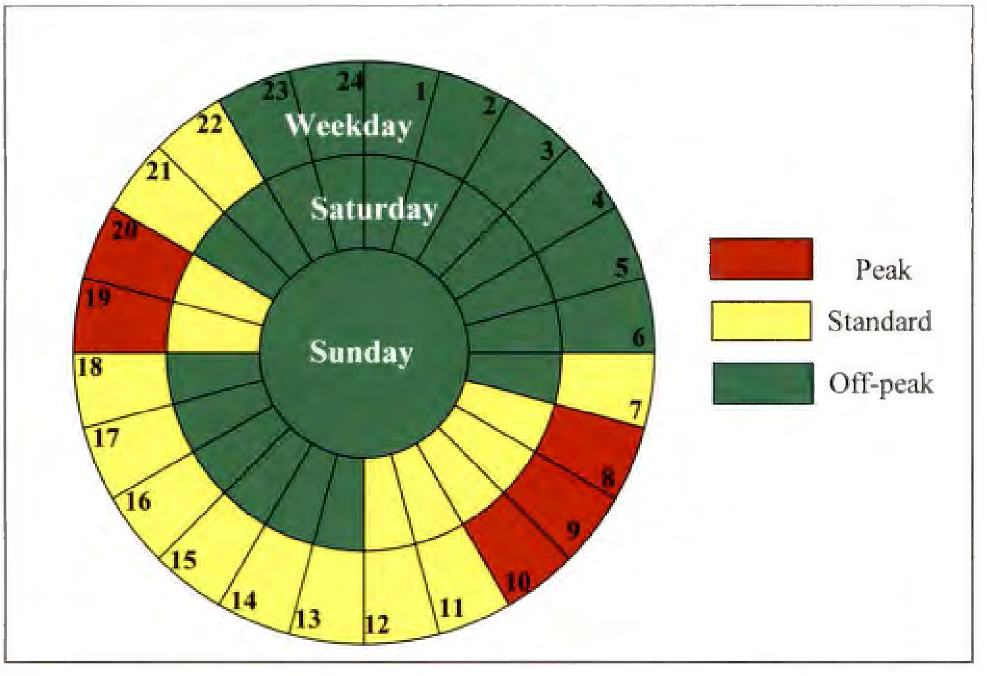

Figure 2.8: Eskom Megaflex TOU periods - Low-demand season

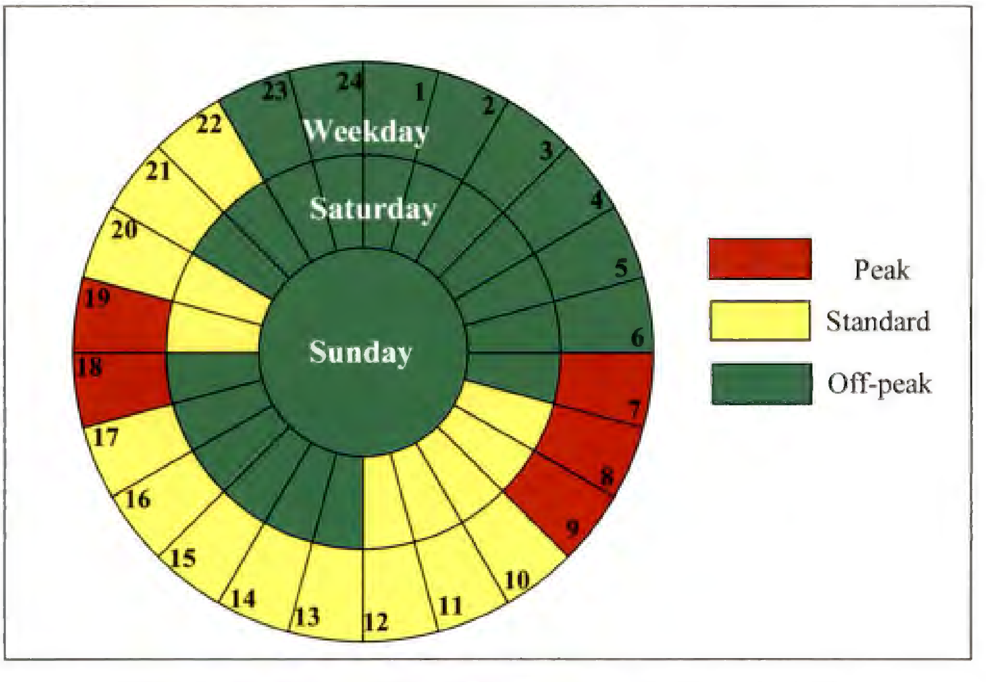

Figure 2.9: Eskom Megaflex TOU periods – High-demand season

2.4.3. Nightsave

The Nightsave tariff structure has TOU demand (kVA) charges and is suitable for cement plants with a high load factor [33]. Nightsave is thus suitable for plants that are not able to shift load. Nightsave has peak and off-peak TOU periods. The TOU periods are structured differently from those of Megaflex. Figure 2.10 shows the Nightsave TOU hours [36].

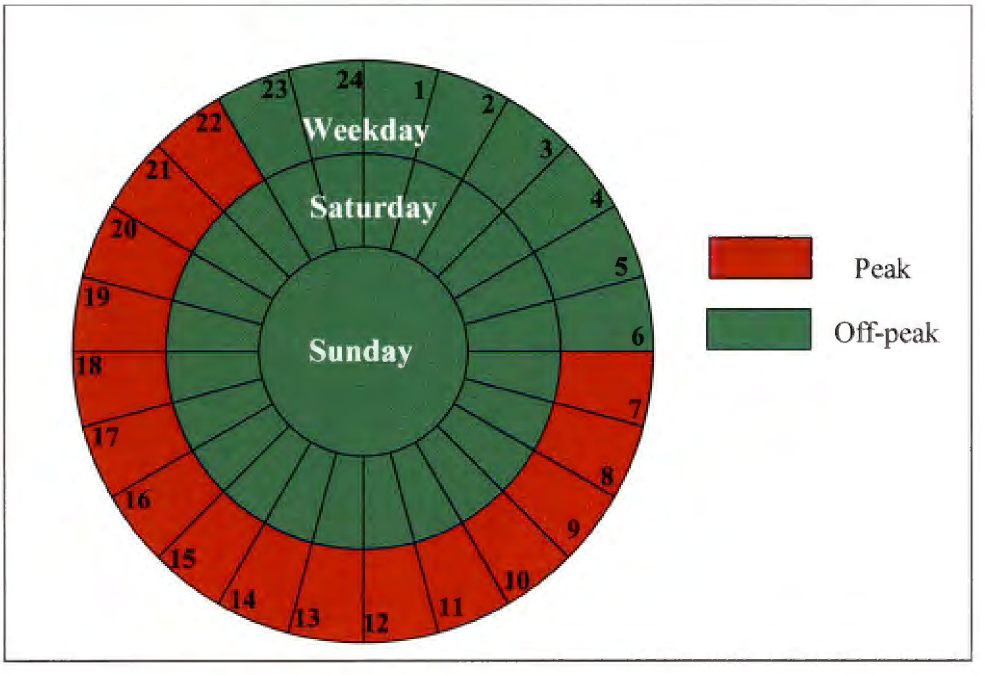

Figure 2.10: Eskom Nightsave TOU periods

2.4.4 Tariff charges

Table 2.3 [36] gives the list of charges found in the Megaflex and Nightsave tariffs. Table 2.3 shows that Megaflex and Nightsave have some charges in common.

Energy charges

Megaflex and Nightsave tariffs have seasonal active energy and demand energy charges. The months of September to May are low-demand months, and the months of June to August are high-demand months. During the low-demand season, where temperatures are high, the demand for electricity in the country is low. The active energy and demand energy charges are therefore lower during these months. The high-demand season has high energy charges due to the high demand for electricity caused by low temperatures.

Table 2.3: Megaflex and Nightsave tariff charges

Charge type	Charge name	Charge units	Megaflex	Nightsave
Energy	Seasonal TOU active energy	c/kWh	√	
	Seasonal Non-TOU Active energy	c/kWh		√
	Seasonal TOU Energy demand	R/kVA/m		√
Transmission and distribution	Transmission network	R/kVA/m	√	√
	Network access	R/kVA/m	√	√
	Network demand	R/kVA/m	√	√
	Urban low voltage subsidy	R/kVA/m	√	√
Other	Electrification and rural network subsidy (ERNS)	c/kWh	√	√
	Reliability service	c/kWh	√	√
	Affordability subsidy	c/kWh	√	√
	Service	R/account/day	√	√
	Administration	R/POD/day*	√	√
	Reactive energy	c/kVArh	√	

*POD is the point of delivery

The active energy charge is an amount charged monthly for every kWh of energy used. The TOU active energy charge differs depending on the time of the day that the kWh were consumed. The peak period has the highest energy charge due to the high demand in electricity. The standard period has the second highest charges, and the low-demand off-peak period has the lowest energy charges. Cement plants that are on the Megaflex tariff will thus see three TOU active energy charges on their monthly bill. The non-TOU active energy charge remains the same throughout the day.

The ED charge is the amount charged for the highest average demand in kVA during the peak periods of the Nightsave TOU hours [40]. This demand is measured every 30 minutes integrating during the peak periods [36]. It is thus important for cement plants to keep their demand low during peak hours in order to reduce their demand costs.

Transmission and distribution charges

Electricity is carried from power stations to substations by high voltage transmission lines. The electricity is then carried to end users such as cement plants via distribution lines [41]. In order for Eskom to recover the costs associated with the transmission and distribution of electricity, industrial electricity consumers are charged for the usage of the transmission and distribution network.

The transmission network charge is the R/kVA network charge that is payable regardless of whether electricity was consumed or not. Cement plants are charged the transmission network charge on their annual utilised capacity (AUC) if maximum demand is measured or on their NMD if maximum demand is not measured. The AUC is the maximum demand of the plant during a rolling 12-month period [36].

The distribution network access (NA) charge is similar to the transmission network charge. It is also charged on either the AUC or the NMD, depending on whether maximum demand is measured. The distribution network demand (ND) is charged on the maximum chargeable demand that is measured during the peak and standard hours of Megaflex, or the peak hours of Nightsave. The urban low voltage subsidy (ULVS) charge is a charge subsidy paid by electricity users with a voltage higher than 66 kV for the benefit of electricity users with a voltage lower than 66 kV [36].

Other charges

The Electrification and Rural Subsidy (ERNS) charge, reliability service charge and the affordability subsidy charge are all charged on the total monthly kWh consumption. The ERNS is a contribution towards socio-economic network-related subsidies for residential and rural tariffs. The reliability service charge is the charge that recovers the cost of providing auxiliary services by the transmission and distribution network operator. The affordability subsidy charge is a charge relating to the supply of electricity to residential areas [36].

The administration charge is charged to recover administration costs such as meter reading, billing and meter capital. The administration cost is charged per point of delivery (POD) for every single day of the billing month. The service charge is the monthly charge that is charged per account to recover service related costs. The service cost is also charged for each day in the billing month [36].

The reactive energy charge is the c/kVArh charge based on the power factor. This charge is levied on the kVArh that is in excess of 30% of the kWh recorded during the peak and standard hours of the Megaflex TOU periods [36]. The reactive energy charge is only applicable during the high-demand season.

2.5. Load shifting on a process plant

2.5.1. Energy management on a process plant

In 2004, Eskom initiated a DSM programme in the residential, commercial and industrial sectors to help improve energy efficiency and load management in South Africa [12]. The name of the programme was later changed to Integrated Demand Management (IDM). Through this programme, Eskom hopes to ease the demand for electricity during peak periods, and thus reduce the pressure that the grid is experiencing.

Figure 2.11 shows how the IDM programme is structured [42]. Because process plants form part of the industrial sector, only this sector will be discussed in this study. The TOU tariffs were discussed in Section 2.1.1 and will not be discussed in this section. The focus of this section will be on load shifting in cement plants. The demand market participation (DMP) programme entails the voluntary reduction of load by customers in order to balance the supply and demand of electricity [43]. The DMP programme will also not be discussed in this study.

Energy efficiency on process plants often involves the installation of high-efficiency equipment [10]. Installation of new energy efficient equipment can include replacing old motors, fans and mills by newer energy efficient ones. For example, ball mills can be replaced by the energy efficient VRM. Although electricity efficiency yields significant cost savings, process plants do not always have the capital to fund the replacement of old equipment [44].

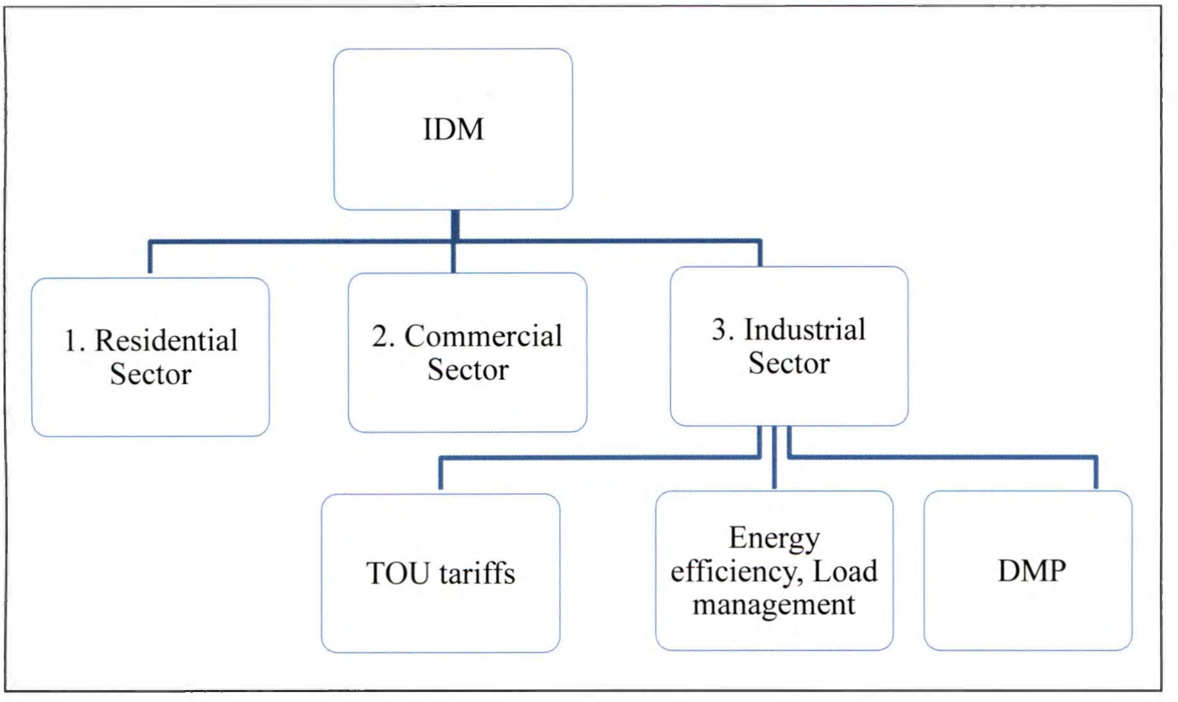

Figure 2.11: Integrated Demand Management Structure

Load management is one of the most feasible ways of reducing electricity costs on a process plant. Load management does not require any major equipment replacement or large capital expenditure. Though load management does not always equate to better energy efficiency, process plants do however, realise large cost savings by implementing it [17].

Load management includes shifting load from the peak demand periods to the off-peak or standard demand periods. In cement and slagment plants, the mills use the largest amount of electricity. For this reason, load shifting in this study will be largely focused on the mills.

During load shifting, the following criteria must be met to ensure that production is not compromised [45]:

1. The upstream and downstream storage capacity must be adequate. This allows the continuous operation of the equipment that does not take part in the load shifting.
2. The production throughput of the plant should not be compromised. The plant should reach the set production volume targets.
3. In the less expensive periods, the equipment that is shut off during load shifting must be able to compensate for the lost production.

4. The post-implementation electricity usage should not be more than the pre-implementation electricity consumption for the same production volume.

A key variable in load shifting is the number of hours available for load shifting to take place. The load shifting hours are determined in a simulation model. The model simulates a number of different production scenarios in order to determine the optimal hours available for load shifting. Before the load shift hours (LSH) can be determined, the monthly production capacity (MPC) of the plant and the silo levels need to be simulated. The calculation of the MPC and simulation of the silo levels on a cement plant will now be discussed [11].

2.5.2. Monthly production capacity

The first step in doing load shifting on a cement plant is to determine if load shifting is viable on the raw mills and cement mills. For the raw mills, this is done by comparing the combined MPC of all the raw mills with the raw meal requirement of the kilns. For the cement mills, this is done by comparing the combined MPC of the cement mills with the production targets of the plant.

The MPC of the mills takes the monthly maintenance hours (MH) and the reliability of the equipment into account. Even with regular scheduled maintenance, mills sometimes break down unexpectedly and are therefore not always reliable. Reliability is measured in how dependable the regularly maintained mills are. The MPC of the plant is calculated as follows:

$$Eq\ 2.1 \qquad MPC = (24 \times days\ in\ the\ month - MH) \times R \times HO$$

Where:
MH: Maintenance hours
R: Reliability factor
HO: Hourly output of the mill

The combined MPC of the raw mills is calculated by summing all the MPCs of the raw mills. The MPC of the raw mills equates to the total monthly raw meal production. This MPC is compared to the MPC of the kilns. The MPC of the kilns is the total monthly clinker production. With the kiln feed to clinker conversion factor known, the amount of raw meal that needs to be fed to the kiln can be calculated from the MPC of the kilns.

The MPC of the raw mills is then compared to the raw meal requirement of the kilns. If the MPC of the raw mills is significantly higher than the raw meal feed, the load shifting is viable on the raw mills. This is because the raw mills are able to supply raw meal at a higher rate than what is needed by the kiln. The switching off of the raw mills during certain peak hours will therefore not affect the kiln.

The MPC of the cement mills is also calculated as indicated in Equation 2.1. The combined MPC of the mills is compared to the production targets of the plant to see if load shifting of the mills is possible. It is important to compare the MPC of the cement mills with high production targets to ensure that production targets are met even during high production months. If the MPC of the mills is higher than the production targets, then load shifting on the cement mills is viable.

Another way of identifying the viability of load shifting on the raw mills and cement mills is to look at the baselines and the operating capacities of the mill motors. In Figure 2.12 the red line shows the motor capacity of the plant and the blue line shows the baseline of the mill [17]. From this figure, one can see that the mill is not operating at full capacity, and can therefore be load shifted.

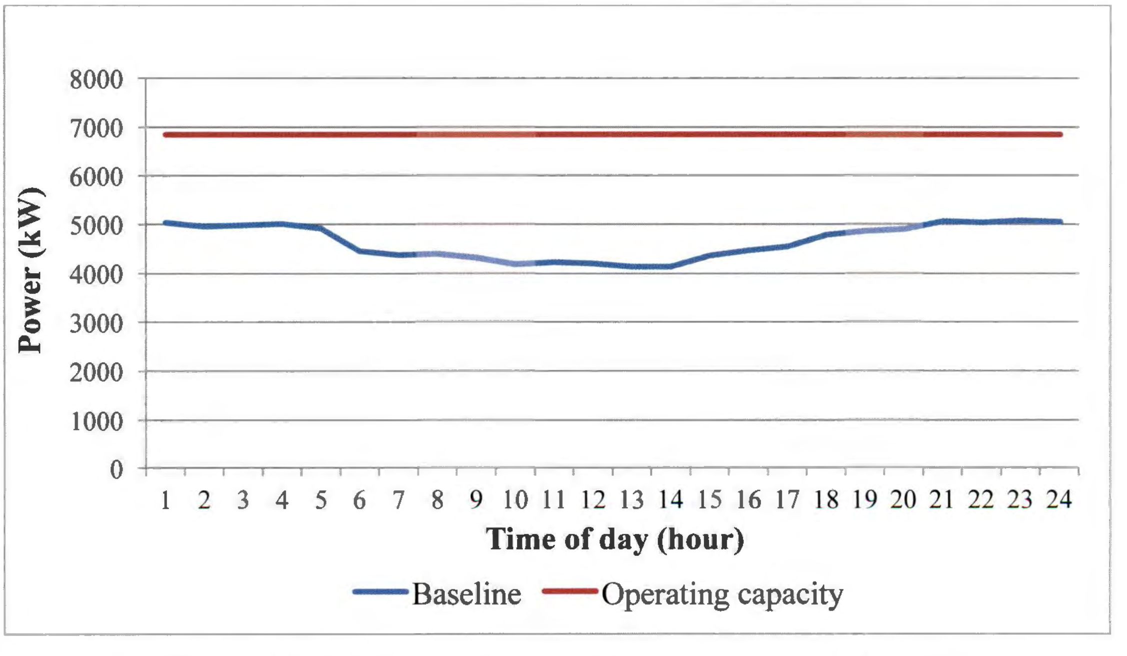

Figure 2.12: Baseline and operating power capacity of a mill

2.5.3. Raw meal silo simulation

During load shifting, the silo level has to stay between the specified minimum and maximum capacities. The simulation model uses different LSH as inputs and simulates how the silo level changes with load shifting. The silos that are simulated are the raw meal silos and the clinker silos as they are most affected by the load shifting of the raw mills and the cement mills.

The raw meal silo levels are directly affected by the raw mill and the kiln as shown in Figure 2.13 [17]. Due to the kiln operating 24 hours a day, the load shifting of the raw mill may cause the levels of the raw meal silo to decrease below the minimum capacity. The raw meal silo simulation therefore calculates the optimal load shifting hours of the raw mill that will not result in the raw meal silo level being too low.

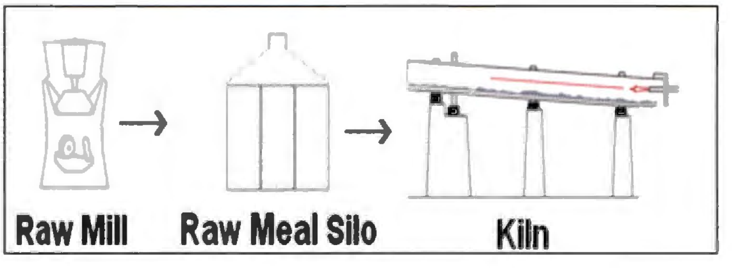

Figure 2.13: Raw meal silo

Data from the raw mill, silo and kiln is used in this simulation. This data can be found from the supervisory control and data acquisition (SCADA) system of the plant. The following data is used in the simulation:

1. The silo data gives the actual level of the silo before the simulation is done. This level will then be simulated to see how it changes with load shifting.
2. The raw mill data provides the inflow rate of the silo and the reliability factor of the mill.
3. The kiln data provides the outflow rate of the silo and the reliability of the kiln.

Other data that will be used is the planned MH of the raw mill and the kiln. Scheduled maintenance of equipment should take place regularly in order to minimise the effects of wear and tear on the equipment.

The data from the SCADA and the maintenance plan is then used to calculate the operating hours (OH) of the equipment and the silo level change. The OH determines the amount of outgoing and incoming flow of material in the silo; it therefore affects the change in silo level [49]. The OH of the raw mill and kiln is calculated as follows:

$$Eq. 2.2 \qquad OH = (24 - MH - LSH) \times R$$

Where:
MH: Maintenance hours
LSH: Load shifting hours
R: Reliability factor

The change in the silo level is then calculated as:

$$\begin{aligned} Eq. 2.3 \quad Change\ in\ silo\ level &= original\ silo\ level + material\ in - material\ out \\ &= original\ silo\ level + (flow\ rate\ in \times OH\ of\ raw\ mill) \\ &- (flow\ rate\ out \times OH\ of\ kiln) \end{aligned}$$

The silo simulation uses different load shifting hours and checks the corresponding silo level change. The goal is to find the optimal load shifting hours that will result in the silo level remaining at the specified minimum and maximum capacities.

2.5.4. Clinker silo simulation

The clinker silo simulation is affected by the kiln, the clinker silo and the cement mill. The SCADA data of equipment and the maintenance plan data are used in the calculation of the OH and the silo level change. The OH of the kiln and cement mill is calculated as indicated in Equation 2.2. The clinker silo level change is then calculated as:

$$\begin{aligned} Eq. 2.4 \quad Change\ in\ silo\ level &= original\ silo\ level + material\ in - material\ out \\ &= original\ silo\ level + (flow\ rate\ in \times OH\ of\ kiln) \\ &- (flow\ rate\ out \times OH\ of\ cement\ mill) \end{aligned}$$

Figures 2.14 shows an example of simulated level changes of a silo [17]. The green and blue lines show the minimum and maximum capacities respectively. The solid blue line shows the simulated silo level change.

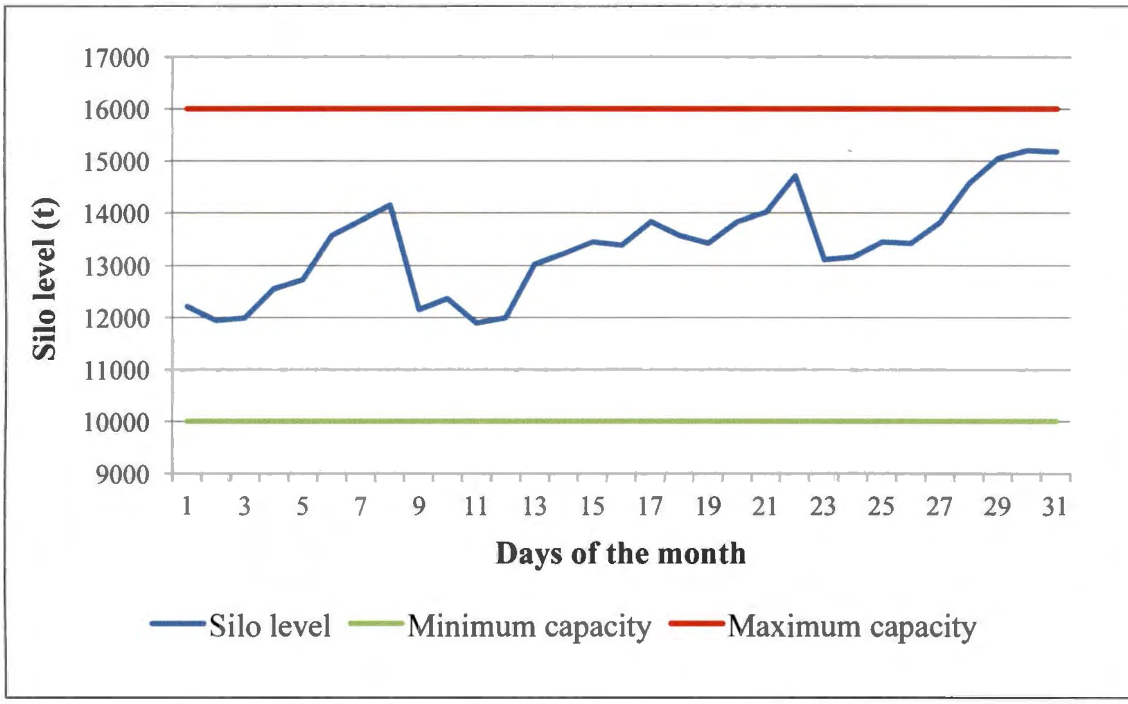

Figure 2.14: Change in silo level

2.5.5. Optimised profile

With the silo levels simulated and the optimal LSH known, the optimised power profile can now be simulated. The mills are switched off during the peak hours, thereby consuming no electricity during those periods. The load is shifted from the peak hours to the off-peak hours and standard hours during weekdays. The load can be shifted from both the morning peak and evening peak periods, but Eskom prioritises load shifting during the evening peak period because of the very high demand during that period.

The optimised off-peak and standard hour load is calculated as the old off-peak and standard baseline load plus the load shifted from the peak hours. This optimised off-peak and standard should not be bigger than the operating capacity of the mill motors. As shown in Figure 2.8 and Figure 2.9, there are eight off-peak hours and eleven standard hours in each weekday. The load taken from the peak hours must be distributed between these nineteen off-peak and standard hours. The optimised off-peak and standard load is calculated as:

$$Eq. 2.5 \quad optimised\ off-peak\ load = baseline\ off-peak\ load + \frac{peak\ load\ shifted}{19}$$

$$Eq. 2.6 \quad optimised\ standard\ load = baseline\ standard\ load + \frac{peak\ load\ shifted}{19}$$

Because the entire load is shifted from the peak hours, the peak load shifted in Equation 2.5 and Equation 2.6 is equal to the baseline peak load. Figure 2.15 shows the optimised power profile, baseline and the operating capacity of a mill during the summer season [17]. The load has been shifted from both peak periods to the off-peak and standard periods.

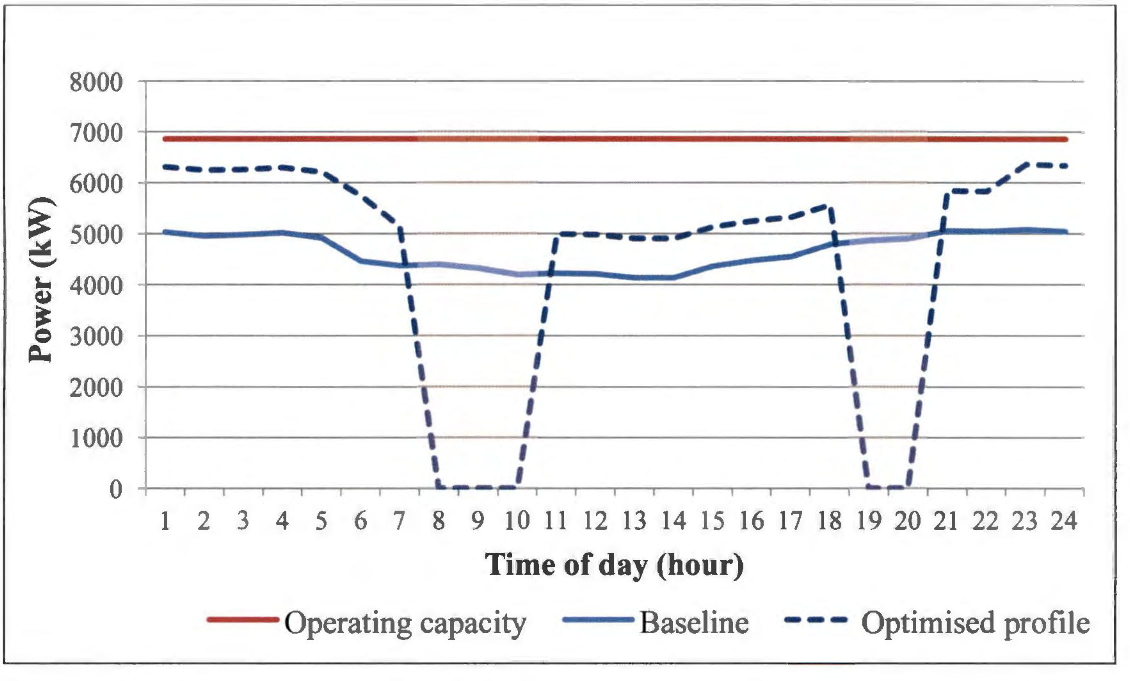

Figure 2.15: Optimised weekday power profile

The total load shifted in one month is dependent on the number of LSH in that month. The total monthly load shifted is calculated as:

$$Eq. 2.7 \quad Monthly\ load\ shifted = LSH \times daily\ load\ shifted$$

A number of studies and projects on load management on South African cement plants have been done. Swanepoel *et al.* implemented energy management system (EnMS) projects where the operational hours of the mills were managed. These projects achieved cost savings of over R8.5 million in a period of five months. These projects were implemented on three of the cement plants in South Africa.

2.6. Conclusion

In this chapter the cost saving opportunities on a process plant were discussed. These cost saving opportunities are various tariff structures and the implementation of load shifting. Tariff structures were designed to be cost reflective, therefore allowing electricity consumers to pay only for the electricity they consumed. The tariff structures were designed in a way that would accommodate various process plants.

The implementation of load shifting can help process plants lower their electricity costs. Before load shifting is implemented, a simulation should first be done to determine the impact of the load shifting on the production of the plant. This simulation will also help the plant to determine how much load can be shifted from the peak periods to the off-peak and standard periods.

Tariff structures and load shifting are a good way for plants to lower their electricity costs. It is however, important to know which tariff structure is the best for the plant. The following chapter helps process plants select the best tariff structure for their plants.

Chapter 3: Tariff structure selection model

3.1. Overview

In this chapter, the calculation methodology is discussed. The inputs and the simulated outputs of the model are described in detail. The model has three types of inputs, namely, production, energy and tariff structure inputs. The model uses these inputs to simulate the cost of electricity for the different tariff structures. The main purpose of the model is to calculate which tariff structure has the lowest electricity costs.

The simulation is divided into two categories, i.e. a simulation where no load shifting occurs and a simulation where load shifting takes place. All the simulations calculations are done on a monthly basis where each month is assumed to have 31 days. Figure 3.1 gives an overview of how the model is structured.

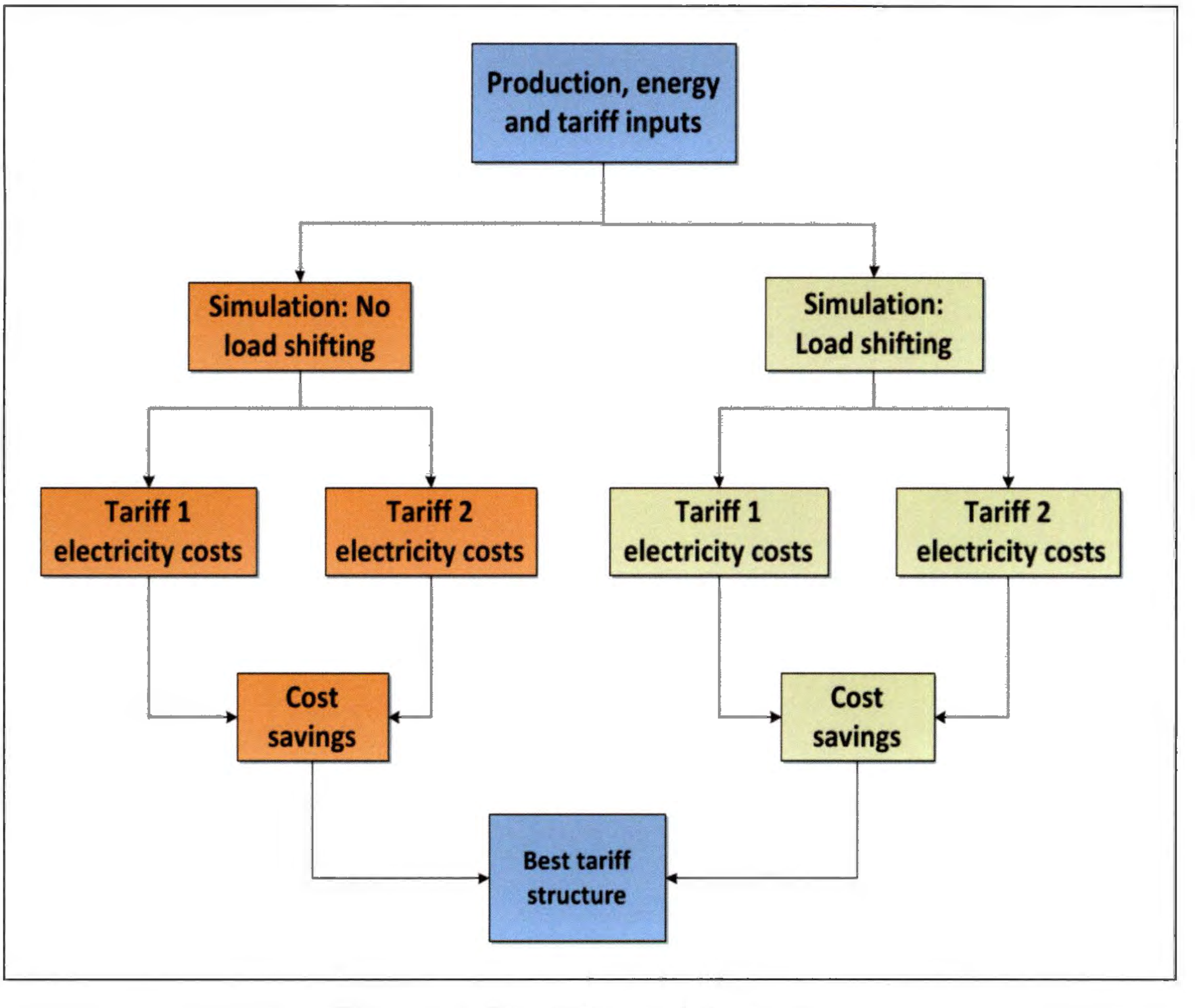

Figure 3.1: Simulation model overview

3.2. Production inputs

3.2.1. Availability

The availability factor (AV) relates to the amount of time that a mill is available for production; it is expressed as a number between 0 and 1. Availability is a function of scheduled maintenance and reliability of the mill. The scheduled maintenance and reliability of the mill can also be expressed as factors, they are calculated as follows:

$$Eq.3.1 \qquad M_S = \left(1 - \frac{scheduled\ maintenance\ hours}{calendar\ hours}\right)$$

Where:

M_S is the scheduled maintenance factor.

$$Eq.3.2 \qquad R = \left(1 - \frac{unscheduled\ maintenance\ hours}{calendar\ hours}\right)$$

Availability is then calculated as:

$$Eq.3.3 \qquad AV = (1 - M_S - R)$$

3.2.2. Hourly output of mills

Mills are designed to operate at different HOs. The HO of the mills is also dependent on the upstream and downstream storage capacity, and the production demand. The total HO of the mills is the sum of the HOs of all mills.

3.2.3. Production volume

Although there are a number of factors that influence the electricity consumption, the primary driver in electricity consumption is production volume (PV). An increase in PV results in an increased electricity consumption, and thus an increase in the cost of electricity. PV on cement plants and slag milling plants is expressed in tonnes.

The PVs of each plant range from minimum to maximum production capacity. Some of the factors that affect PVs are storage capacity, availability of the processing equipment and forecasted sales. It is important that the calculation of electricity costs is done for a set of PVs satisfying the following criteria:

$$Eq. 3.4 \qquad minimum\ production \leq PV \leq maximum\ production$$

The minimum production differs from one plant to another. The maximum production for each month can be calculated from the MPC of the plant. Due to the kiln operating at rates slower than those of raw mills and cement mills, the MPC of a cement plant will usually be equal to the MPC of the kiln/s. The MPC of the kiln is calculated as:

$$Eq. 3.5 \qquad MPC = (24 \times days\ in\ the\ month - MH) \times R \times HO$$

Where:
MH: Maintenance hours
R: Reliability factor
HO: Hourly output of the kiln

The total MPC of the plant would then be equal to the sum of the MPCs of all the operational kilns on the cement plant. The MPC of a slag milling plant will be determined by the MPCs of all the operational mills on the plant. The MPC of the mills is calculated as indicated in Equation 3.5, with HO, the hourly output of the mills.

3.2.4. Capacity Utilisation

The capacity utilisation (CU) is a measure of the utilisation of the production capacity of the plant. CU is expressed as a percentage that can range from 0% to 100% capacity. The CU is calculated as:

$$Eq. 3.6 \qquad CU = \frac{actual\ production\ volume}{maximum\ production\ volume} * 100$$

3.3. Energy inputs

3.3.1. Specific energy consumption

The specific efficiency consumption (SEC) of a mill is the amount of energy it uses to process a specific volume of product. The SEC is a measure of how energy efficient a mill is. The overall SEC is the average of specific energy consumptions of all the mills; this overall SEC is used in the calculations. The SEC can be calculated from historic PVs and historic energy consumption (E) data as shown in Eq. 3.7 below:

$$Eq. 3.7 \qquad SEC = \frac{E}{PV}$$

3.3.2. Notified maximum demand (NMD)

The NMD is the maximum contracted demand of the plant. The plant notifies Eskom of the demand and Eskom accepts it in the form of a contract. Penalties occur when the plant's maximum demand exceeds the NMD. The NMD is important in determining which tariff structures are relevant to the processing plant. Tariff charges such as the NA charge and the transmission network charge are billed on the NMD.

3.3.3. Utilised demand (UD)

The utilised demand (UD) is the maximum average energy of the plant in kVA that is being consumed in a 30 minute integrating period [36]. It is measured in the peak and standard periods and for the Nightsave tariff it is measured during the peak periods. The UD increases with an increase in the number of operational processing mills. The maximum demand of each mill is calculated as:

$$Eq. 3.8 \qquad UD = \frac{Running\ motor\ capacity}{Power\ factor}$$

The running motor capacity and power factor can be found from the historic data of the mills. The total maximum demand is the sum of the maximum demands of all the mills in operation.

3.3.4. Baseline electricity usage

The baseline electricity utilisation is the electricity consumption of the plant when no load shifting takes place. This baseline consumption can be represented as a percentage of electricity consumed during the peak, standard and off-peak hours. The percentage of electricity consumed during the peak, standard and off-peak hours is calculated from historic data as follows:

$$Eq. 3.9 \qquad Peak\ distribution = \frac{Electricty\ consumed\ during\ peak\ periods}{Total\ monthly\ electricity\ consumption} \times 100$$

$$Eq. 3.10 \qquad Standard\ distribution = \frac{Electricity\ consumed\ during\ standard\ periods}{Total\ monthly\ energy\ consumption} \times 100$$

$$Eq. 3.11 \qquad Off-peak\ distribution = \frac{Electricity\ consumed\ during\ off-peak\ periods}{Total\ monthly\ electricity\ consumption} \times 100$$

As stated previously, the amount of electricity consumed changes with a change in CU. It will however, be assumed that the peak, off-peak and standard hour electricity distribution will remain constant with a change in CU. An example of the utilisation distribution is shown in Figure 3.2.

3.3.5. Optimised electricity distribution

The majority of processing plants are able to shift load because they do not operate at full capacity. As discussed in Section 2.5, a simulation needs to be done in order to determine the load shifting potential of the plant. Figure 3.3 shows the steps that need to be taken during the simulation of the load shifting potential.

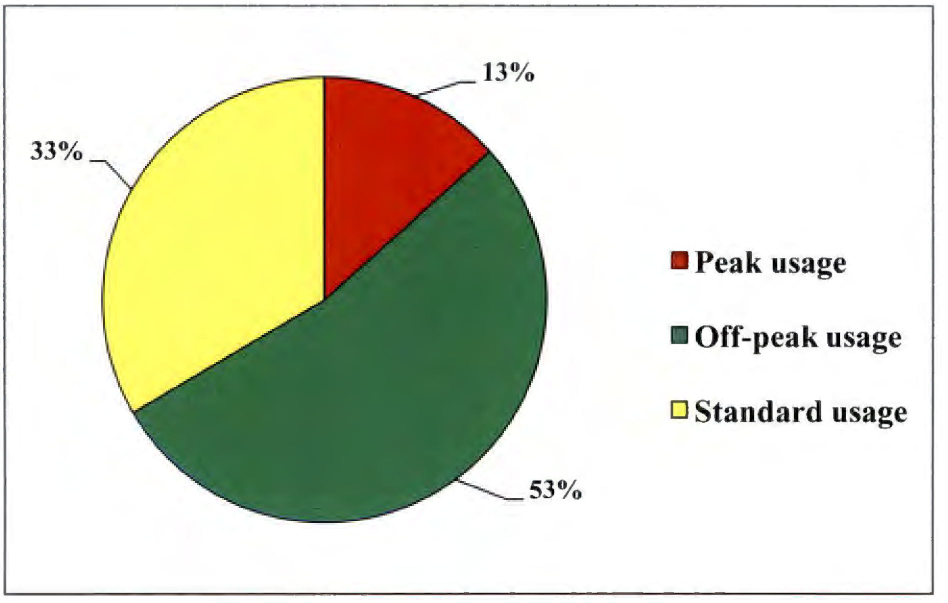

Figure 3.2: Baseline TOU electricity distribution

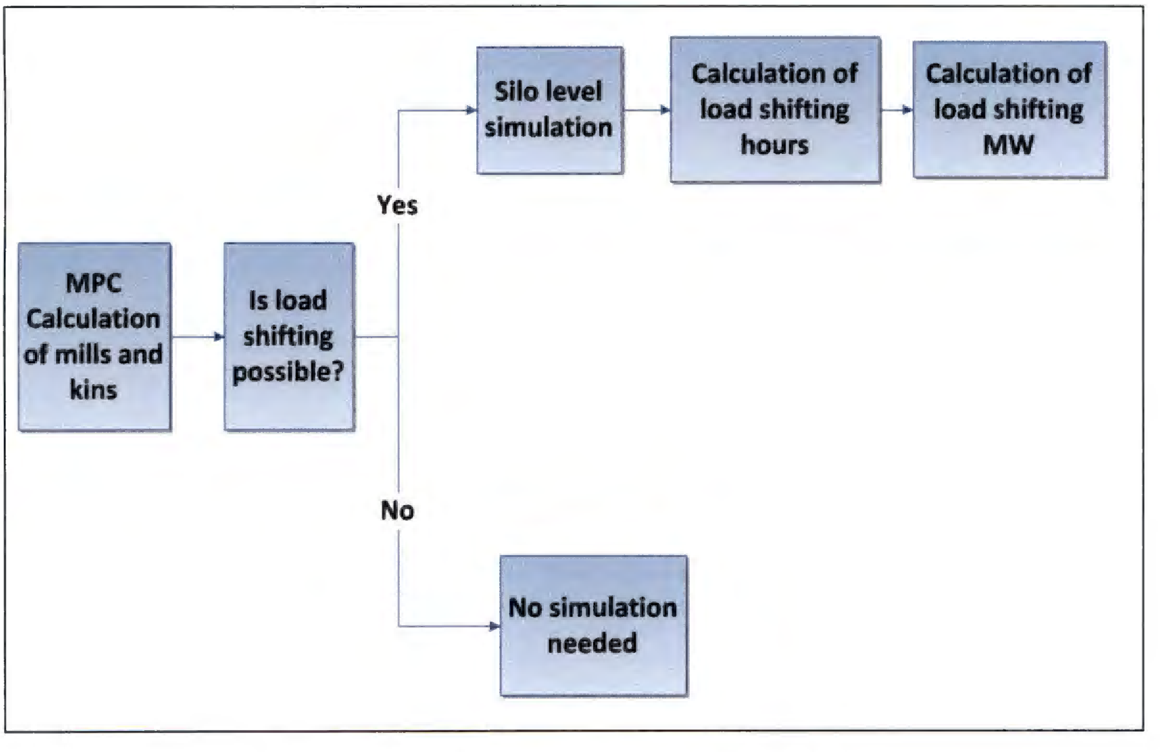

Figure 3.3: Load shifting simulation summary

The load shifting potential of the plant changes as the CU of the plant changes. Therefore, the simulation needs to be done for all the CUs. The steps of this simulation will be the same for all the CUs. The only change in the simulation is the MPC of the mills and the kilns. The

MPC of each mill and kiln will change as the CU changes. Equation 3.12 shows the calculation of the MPC of the mills and kilns for each CU.

$$Eq. 3.12 \qquad MPC_i = \big((24 \times days\ in\ the\ month - MH) \times R \times HO\big) \times CU_i$$

Where:

MPC_i: MPC for specific capacity utilisation percentage

CU_i: Capacity utilisation percentage

MH: Maintenance hours

R: Reliability factor

HO: Hourly output of the kiln

After determining the load shifting potential of the plant for each utilisation capacity, the optimised peak, standard and off-peak distribution can be calculated. These are calculated as indicated in Equations 3.9-3.11. Figure 3.4 shows an example of an optimised electricity distribution. The peak electricity usage has been decreased significantly.

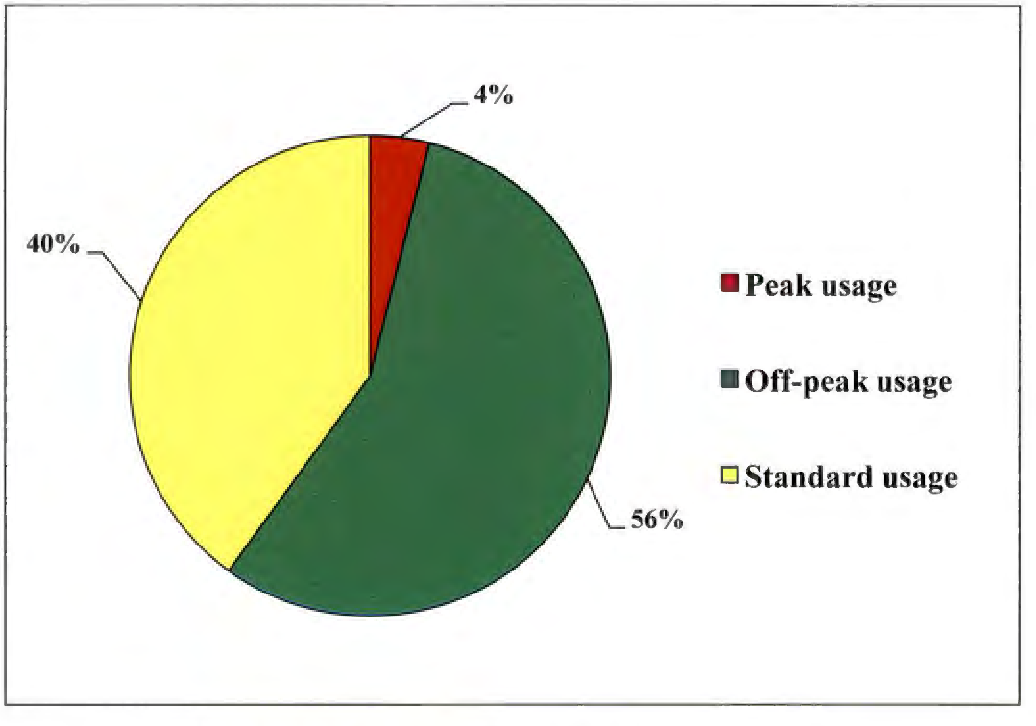

Figure 3.4: Optimised TOU electricity distribution

3.4. Tariff structure inputs

3.4.1 Tariff structures and charges

The majority of the processing plants in South Africa are supplied with electricity by either their local municipalities or Eskom. This calculation method is designed for the use of any Eskom or municipal tariff structure for industrial electricity consumers. With a variety of tariff structures available for industrial electricity consumers, it is important for process plants to know which tariff structures they can compare in order to find the best tariff structure for the plant.

The NMD of the plant can be used as a guide for selecting the tariff structures a process plant can compare. This is because each tariff structure is characterised by a specific range of NMDs. Table 3.1 shows a range of NMDs and the corresponding tariff structures that can be compared for that range. Eskom tariff structures can be compared with municipality tariff structures.

Table 3.1: Comparable electricity tariff structures

NMD	Comparable tariff structures
25 kVA ≤ NMD ≤ 1 MVA	Nightsave urban small Miniflex Applicable municipal tariff structures
1 MVA < NMD ≤ 5 MVA	Nightsave urban large Miniflex Megaflex Applicable municipal tariff structures
NMD > 5 MVA	Nightsave urban large Nightsave Applicable municipal tariff structures

Each tariff structure has various types of charges, such as energy, demand and service charges. These charges are grouped according to the transmission zone and the voltage supply of the plant. Table 3.2 gives the different types of charges for the various tariff structures. The Eskom tariff charges can be found on the Eskom website. The municipality tariff charges are found in municipality tariff booklets.

3.5. Simulation

3.5.1 Preamble

There are two types of simulations that take place, the simulation when no load shifting occurs, and the simulation where load shifting takes place. The simulation calculations of these two scenarios are similar for the most part, only the calculation of the TOU electricity consumption varies.

Table 3.2: Electricity tariff charges

Charge type	Charge name	Charge units
Energy	Seasonal TOU active energy	c/kWh
	Seasonal non-TOU active energy	c/kWh
	Seasonal TOU energy demand	R/kVA/m
Transmission and distribution	Transmission network (TN)	R/kVA/m
	Network access (NA)	R/kVA/m
	Network demand (ND)	R/kVA/m
	Urban low voltage subsidy (ULVS)	R/kVA/m
Other	Electrification and rural network subsidy (ERNS)	c/kWh
	Reliability service (RS)	c/kWh
	Affordability subsidy (AS)	c/kWh
	Service	R/account/day
	Administration	R/POD/day

3.5.2 Number of mills in operation

A change in PV changes the amount of electricity consumed and consequently the electricity costs. The PV is therefore a main independent variable in the simulation. As the PV increases, so does the number of mills that need to be in operation. The number of mills that are running influences the demand and the electricity consumption. This first step in the simulation is therefore determining the number of mills needed for a specific PV.

This is done by comparing the MPC of the mills with the monthly PV. For a cement plant these will be the finishing mills, as they mill the finished product. The availability of the mills plays an important role in the MPC of the mills. A high availability results in a large MPC of a mill. For a cement plant with three finishing mills, the MPCs are calculated as follows:

$$Eq. 3.13 \qquad MPC_1 = 24 \times 31 \times HO_{m1} \times AV_{m1}$$

$$Eq. 3.14 \qquad MPC_2 = MPC_1 + 24 \times 31 \times HO_{m2} \times AV_{m2}$$

$$Eq. 3.15 \qquad MPC_3 = MPC_2 + 24 \times 31 \times HO_{m3} \times AV_{m3}$$

Where:
MPC_n: MPC of the mills, subscript *n* represents the number of mills that are in operation
HO_{mi}: Hourly output of each mill, subscript *mi* represents mill 1, mill 2 and mill 3
AV_{mi}: Availability of each mill, subscript *mi* represents mill 1, mill 2 and mill 3

The MPC of the mills needs to be greater than the PV it is being compared to. This signifies that the mills have enough capacity to meet the production demands of that specific PV. The PV is firstly compared to the MPC_1, which is the MPC when one mill is running. If this MPC is smaller than monthly PV, then the model compares the MPC of two mills, i.e. MPC_2.

This comparison continues until the model finds an MPC of the mills that is greater than the PV. Figure 3.5 shows the steps the model takes to determine the number of mills needed for a specific PV.

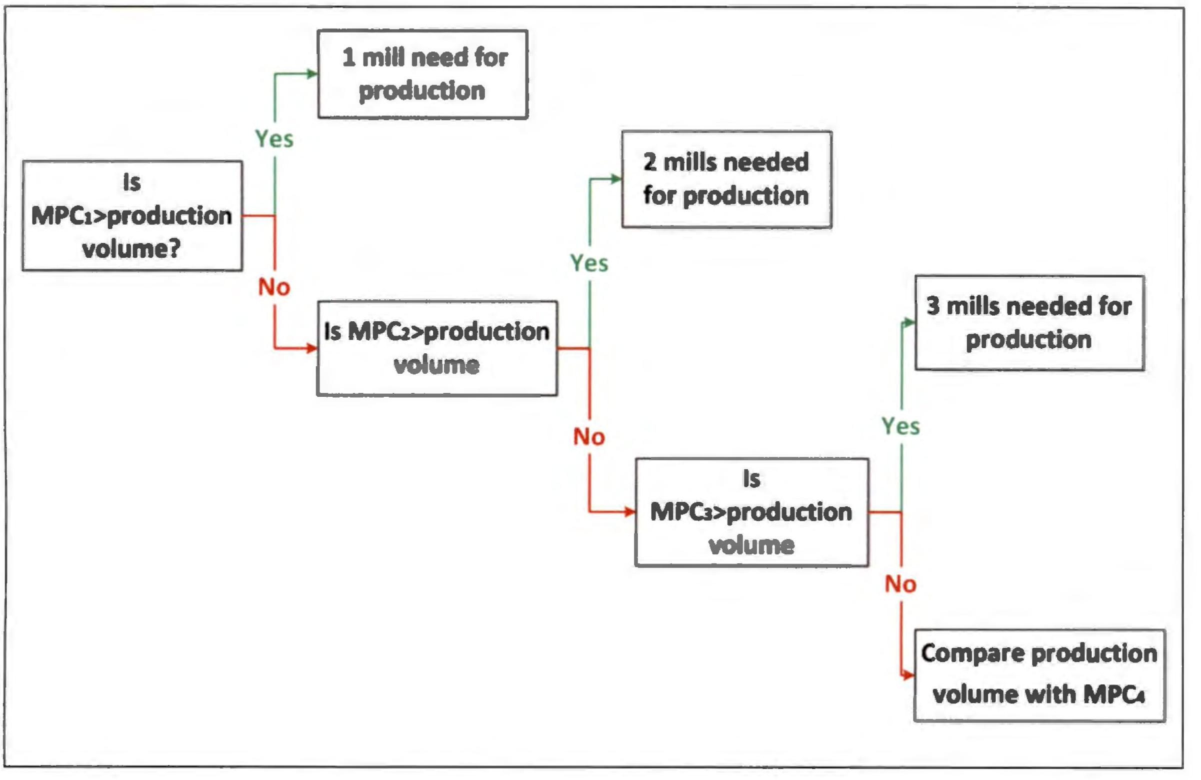

Figure 3.5: Determination of the number of mills needed for production

3.5.3 Utilised demand

Once the number of mills needed for each PV has been determined, the monthly UD can now be calculated. The demand of the mills was given as an input. The simulation checks the number of the mills that are needed for a specific PV and then calculates the corresponding demand for that particular number of mills. When more than one is running, the demand will be the sum of the mills.

3.5.4 Total electricity consumption

One of the key simulations is the calculation of the total (monthly) electricity consumption for a specific PV. The kWh is calculated from the PV and the SEC inputs. For every PV, the energy consumed is given as:

$$Eq.3.16 \qquad E = SEC \times PV$$

3.5.5 TOU electricity consumption – No load shifting

The TOU electricity consumption when no load shifting occurs will be calculated from the baseline electricity distribution inputs and the total electricity consumption calculated above.

This is the calculation of the peak, the standard, and the off-peak electricity consumption for each PV. The TOU electricity consumption when no load shifting occurs is calculated as follows:

$$Eq. 3.17 \qquad peak\ electricity\ consumption_{NLS} = E \times peak\ electricity\ distribution_{NLS}$$

$$Eq. 3.18 \qquad standard\ electricity\ consumption_{NLS} = E \times standard\ electricity\ distribution_{NLS}$$

$$Eq. 3.19 \qquad Off-peak\ electricity\ consumption_{NLS} = E \times off-peak\ electricity\ distribution_{NLS}$$

Subscript *NLS* is an acronym for no load shifting.

3.5.6 TOU electricity consumption –Load shifting

When load shifting is implemented, the TOU electricity consumption will be calculated from the optimised electricity distribution inputs and the total electricity consumption for the month. The TOU electricity consumption when load shifting is implemented is calculated as follows:

$$Eq. 3.20 \qquad peak\ electricity\ consumption_{LS} = E \times peak\ electricity\ distribution_{LS}$$

$$Eq. 21 \qquad standard\ electricity\ consumption_{LS} = E \times standard\ electricity\ distribution_{LS}$$

$$Eq. 3.22 \qquad Off-peak\ electricity\ consumption_{LS} = E \times off-peak\ electricity\ distribution_{LS}$$

Subscript *LS* is an acronym for load shifting.

3.5.7 Electricity costs

With the calculation of the electricity consumption complete, the monthly electricity costs for the different tariff structures can now be simulated. These costs consist of energy costs, transmission and distribution costs and other types of costs. The costs are calculated from the charge inputs in Section 3.4. The costs vary from one tariff structure to the other.

The energy costs consist of seasonal active energy and seasonal demand energy costs. The active energy costs can be TOU costs or non-TOU energy costs; this is dependent on the type of tariff structure. The seasonal active energy and demand electricity costs are calculated as follows:

$Eq. 3.23$ $$summer\ peak\ AE\ cost \\ = peak\ electricity\ consumption \times summer\ peak\ AE\ charge$$

$Eq. 3.24$ $$summer\ standard\ AE\ cost \\ = standard\ electricity\ consumption\ \times summer\ standard\ AE\ charge$$

$Eq. 3.25$ $$summer\ off-peak\ AE\ cost \\ = off-peak\ electricity\ consumption \\ \times summer\ off-peak\ AE\ charge$$

$Eq. 3.26$ $$summer\ non\ TOU\ AE\ cost = E * summer\ non\ TOU\ AE\ charge$$

$Eq. 3.27$ $$winter\ peak\ AE\ cost \\ = peak\ electricity\ consumption\ \times winter\ peak\ AE\ charge$$

$Eq. 3.28$ $$winter\ standard\ AE\ cost \\ = standard\ electricity\ consumption \times winter\ standard\ AE\ charge$$

$Eq. 3.29$ $$winter\ off-peak\ AE\ cost \\ = off-peak\ electricity\ consumption \\ \times winter\ off-peak\ AE\ charge$$

$Eq. 3.30$ $$winter\ non-TOU\ AE\ cost = E \times winter\ non-TOU\ AE\ charge$$

$$Eq. 3.31 \qquad summer\ ED\ cost = UD \times summer\ ED\ charge$$

$$Eq. 3.32 \qquad winter\ ED\ cost = UD \times winter\ ED\ charge$$

Where:
AE: Active energy
ED: Energy demand
UD: Utilised demand
E: Total electricity consumption

The next costs that are calculated are the transmission and distribution network costs. These can include costs such as the transmission network (TN), network access (NA), network demand (ND) and the urban low voltage and subsidy (ULVS) cost. The transmission and distribution costs are calculated as:

$$Eq. 3.33 \qquad TN\ cost = NMD \times TN\ charge$$

$$Eq. 3.34 \qquad NA\ cost = NMD \times NA\ charge$$

$$Eq. 3.35 \qquad ND\ cost = UD \times ND\ charge$$

Where:
NMD: Notified maximum demand
UD: Utilised demand

In addition to energy and network costs, there are other costs that need to be calculated. Equations 3.36-3.40 show the calculation of these costs. The ERNS, the reliability services (RS) and the affordability subsidy (AS) costs are calculated as:

$$Eq. 3.36 \qquad ERNS\ cost = E \times ERNS\ charge$$

$$Eq. 3.37 \qquad RS\ cost = E \times RS\ charge$$

$$Eq. 3.38 \qquad AS\ cost = E \times AS\ charge$$

Where:

E: Total electricity consumption

The service and admin costs are calculated as:

$$Eq. 3.39 \qquad service\ \ cost = no.\ of\ days\ in\ the\ month \times service\ \ charge$$

$$Eq. 3.40 \qquad admin\ cost = no.\ of\ days\ in\ \ the\ month \times admin\ charge$$

The total monthly electricity cost for a summer or winter month is the sum of the energy costs, the transmission and distribution network costs and the other costs. These monthly electricity costs are calculated as:

$$Eq. 3.41 \qquad summer\ month\ \ cost \\ = summer\ energy\ costs + nework\ costs + other\ costs$$

$$Eq. 3.42 \qquad winter\ month\ cost \\ = winter\ energy\ costs + network\ costs + other\ costs$$

There are nine summer (low-demand) months and three winter (high-demand) months in a year. The annual electricity cost of each tariff structure is therefore the sum of the nine summer months' costs and the three winter months' costs. The annual electricity cost is calculated as:

$$Eq. 3.43 \qquad Annual\ cost = 9 \times summer\ cost + 3 \times winter\ cost$$

The results of the summer month, winter month and annual electricity costs are plotted on graphs. On the y-axis of the graphs are the CU percentages. The graphs therefore show how the electricity costs of the tariff structures are affected by the change in production CU. An example of each graph is shown in Figure 3.6 – Figure 3.8.

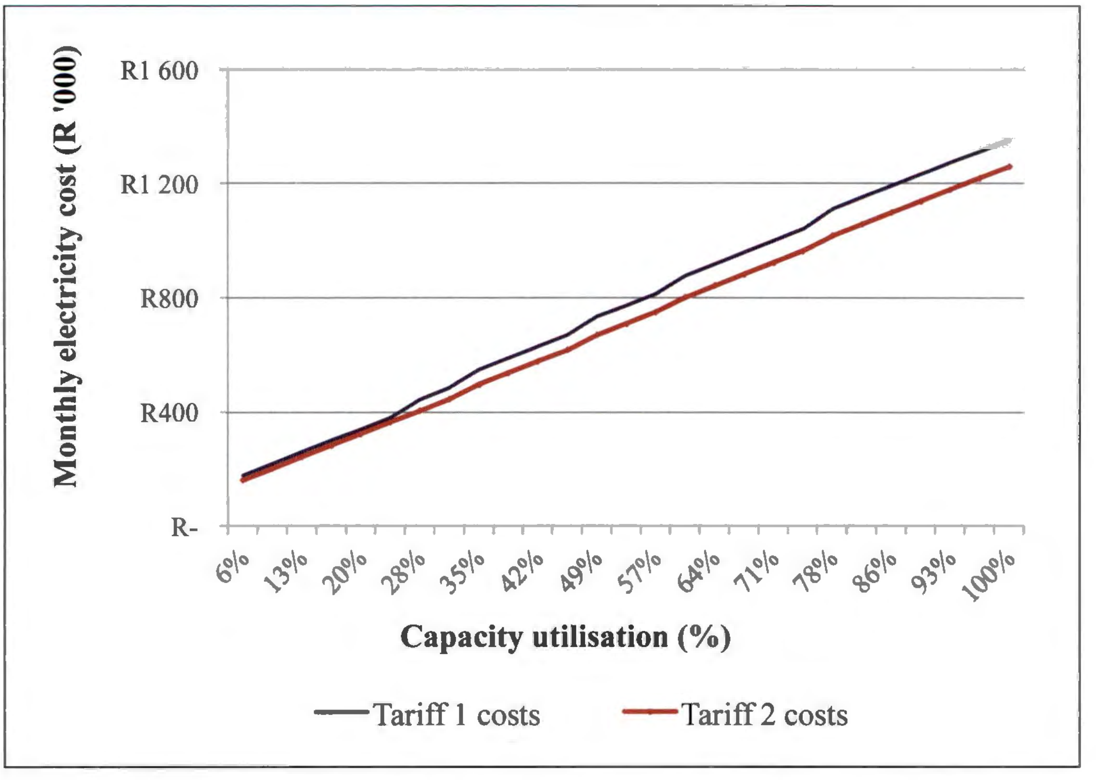

Figure 3.6: Simulated summer month electricity costs

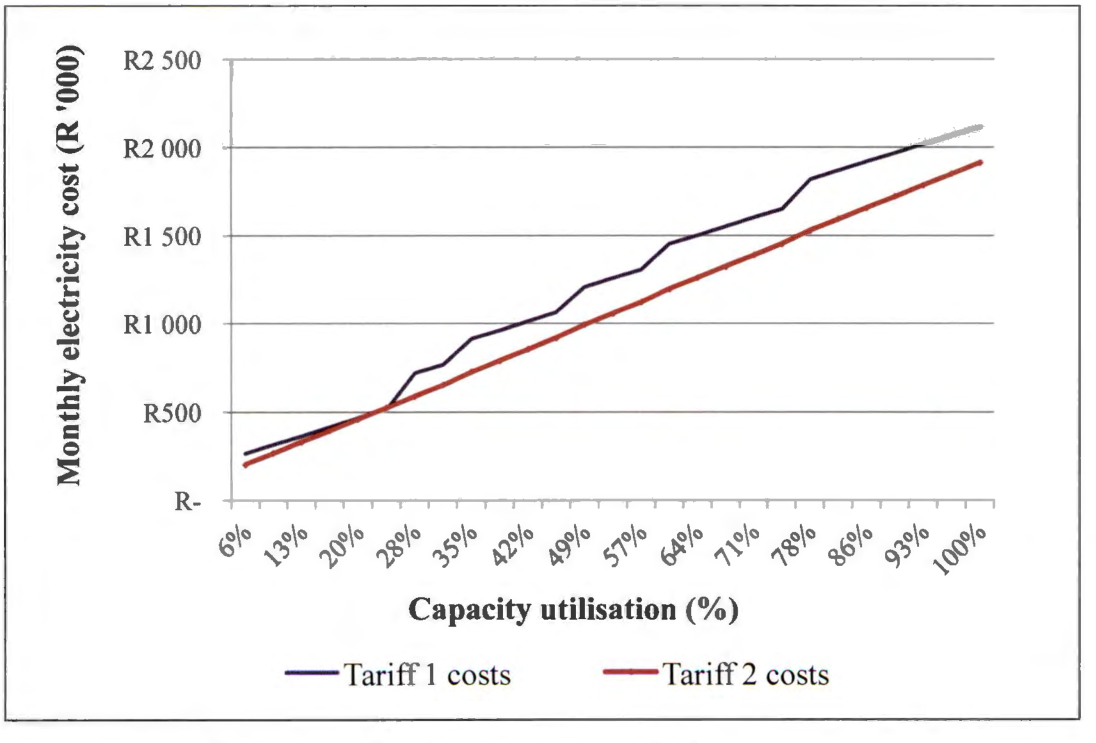

Figure 3.7: Simulated winter month electricity costs

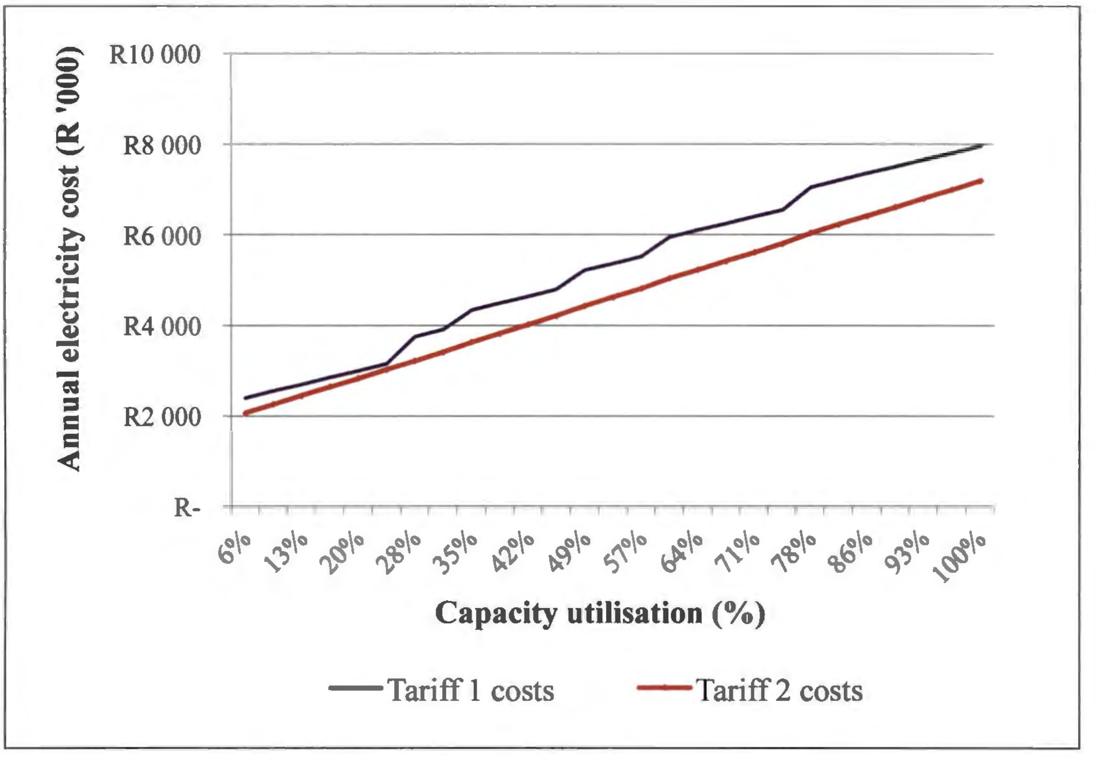

Figure 3.8: Simulated annual electricity costs

3.5.8 Cost savings

The tariff structure that has the lowest electricity costs will have the best cost savings. The model quantifies the savings by subtracting electricity cost of the one tariff structure from the electricity costs of the other tariff structure. The simulation model calculates monthly and annual cost savings at various CUs. The following equations show the calculation of the monthly and annual electricity cost savings

$Eq. 345$

$$summer\ month\ savings = Tariff_1\ summer\ month\ cost - Tariff_2\ summer\ month\ cost$$

$Eq. 3.46$

$$winter\ month\ savings = Tariff_1\ winter\ month\ cost - Tariff_2\ winter\ month\ cost$$

$Eq. 3.47$

$$annual\ savings = 9 \times summer\ month\ savings + 3 \times winter\ month\ savings$$

3.6. Selection of tariff structure

Once the savings have been calculated, a decision on which tariff structure is the best can now be made. If the one tariff structure has lower electricity costs when load shifting is implemented than when it is not implemented, then the tariff structure is the best choice for the process plant. This shows that the electricity costs remain low despite the change in production.

When one tariff structure gives low electricity costs only when load shifting is implemented, then the plant needs to think carefully before choosing that tariff structure. If that particular tariff structure is chosen, the plant needs to be committed to doing load shifting to avoid high electricity costs. This needs careful planning and accurate sales forecasts.

3.7. Conclusion

It is important for process plants to choose the most suitable tariff structure for the plant. Choosing the correct tariff structure will often result in the reduction of electricity costs. The simulation model described in this chapter helps process plants to select the best tariff structure for their plants.

The model does this by using the input data to simulate the electricity cost and cost savings of the different tariff structures. The model has three sets of inputs, i.e. production, energy and tariff structure inputs. All the inputs can be easily calculated from the historical data of the plant. It is important that the input data needed for the simulations is known, as the accuracy of the simulation results are dependent on the accuracy of the input data.

The decision on which tariff structure is the best can be made by comparing the electricity costs of the tariff structures. The costs must be compared during conditions where load shifting takes place and during conditions where no load shifting takes place. The best tariff structure is the tariff structure that always has the lowest electricity costs.

Chapter 4: Results and applications

4.1. Overview

In this chapter, two case studies are presented. The background and basic layout of the case studies are given. The simulation model described in Chapter 3 is then used to decide which tariff structure would result in the lowest electricity costs and thus result in the best electricity cost savings. This is firstly done by giving all the inputs of the model that are needed. The results of the simulation are then presented and discussed and the best tariff structure is identified.

The implementation or actual results are presented and then compared to the simulation results. An analysis is done to determine whether the simulation model was correct in predicting the electricity costs and electricity cost savings.

4.2. Case study 1 – Slagment process plant

4.2.1 Process plant background and layout

The first case study presents a slag milling process plant in South Africa. Figure 4.1 shows a basic layout of the plant which consists of storage, drying, milling and distribution sections. The milling section consists of five ball mills that use electricity as a source of energy. The rotary dryer and hazamac dryer use coal as a source of energy.

4.2.2 Production inputs

Availability and hourly output

Equations 3.1-3.3 were used to calculate the average availability factors of the mills. The availability factors of the mills are given in Table 4.1. Table 4.1 also shows the HO of each mill. Mills 1- 4 are of an equal production capacity; mill 5 has a larger production capacity.

Table 4.1: Availability and hourly production rate of mills

Mill	Availability	Hourly output (tonne/hr)
Mill 1	0.85	16
Mill 2	0.85	16
Mill 3	0.85	16
Mill 4	0.85	16
Mill 5	0.9	50

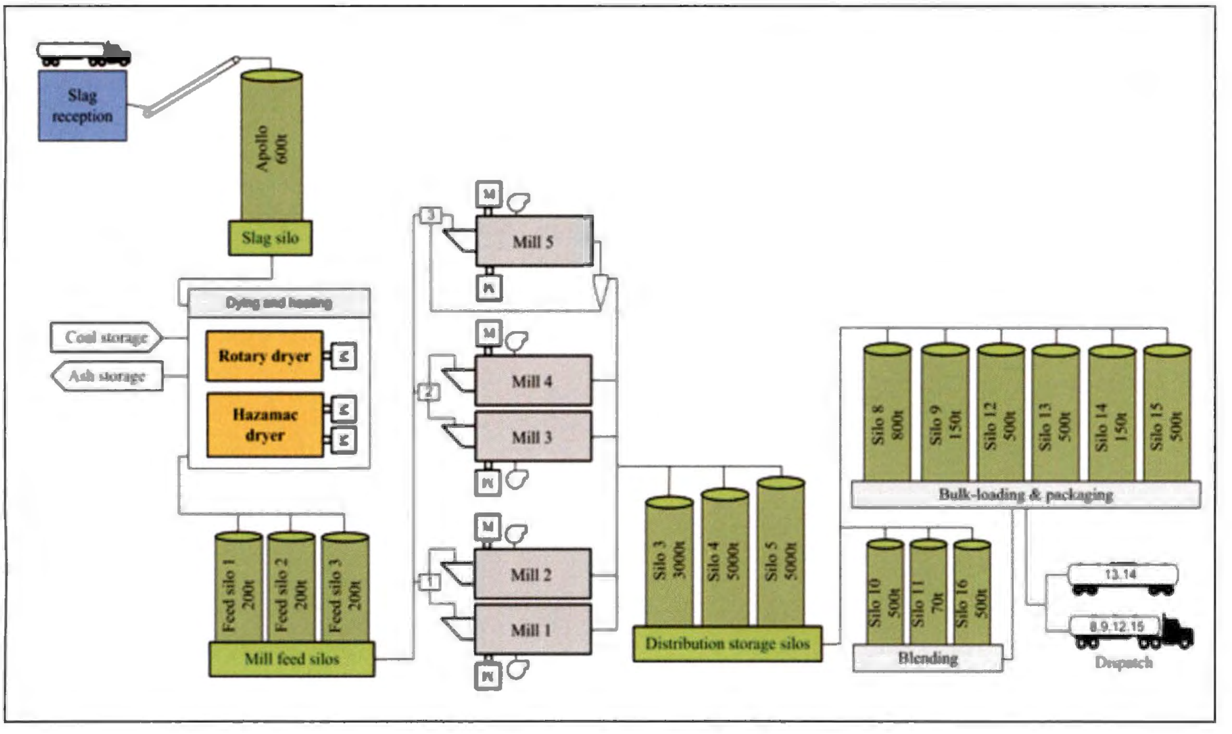

Figure 4.1: Case study 1 plant layout

Production volume and utilisation

The MPC of the plant was calculated as 83 000 tonnes; this is the maximum monthly PV of the plant. From historical data, the minimum monthly PV was calculated as 5 000 tonnes. The average monthly PV was also calculated from historical data; the average PV ranged from 44 000 tonnes to 47 000 tonnes.

The corresponding utilisation capacity percentages were calculated as indicated in Equation 3.10. Table 4.2 shows the minimum, maximum and average PVs and their corresponding utilisation percentages.

Table 4.2: Production volume and capacity utilisation

	Production volume (tonnes)	**Capacity utilisation (%)**
Minimum	5 000	6
Average	44 000 – 47 000	53 - 57
Maximum	83 000	100

4.2.3 Energy inputs

SEC and utilised demand

Table 4.3 shows the UD and the SEC for a particular number of operational mills. The table shows that the UD increases with an increase in the number of operational mills. The average SEC of each mill was calculated according to Equation 3.11. The table shows that the SEC remains constant at 65 kWh/tonne.

Table 4.3: The utilised demand and specific energy consumption of operational mills

Number of operational mills	Utilised demand (kVA)	SEC (kWh/tonne)
1	3 400	65
2	4 600	65
3	5 800	65
4	7 000	65
5	8 500	65

Baseline TOU electricity usage

The baseline electricity usage of the plant is shown in Figure 4.2. The plant did not have any load shifting or load management initiatives in place. As a result, the baseline peak electricity usage of the plant is very high.

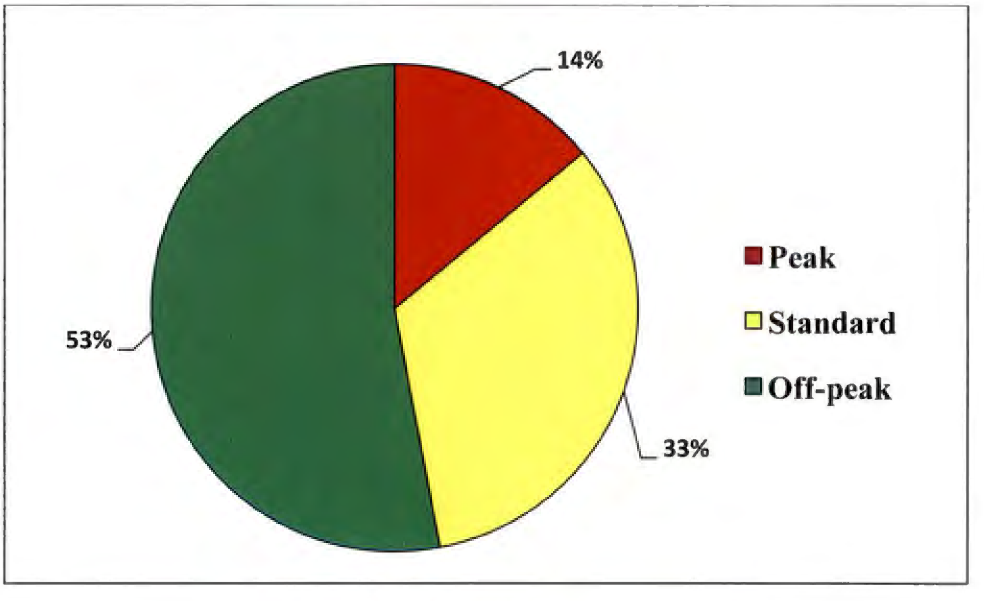

Figure 4.2: Baseline TOU electricity usage

Optimised TOU electricity usage

The optimal TOU electricity usage was simulated as discussed in Sections 2.5 and 3.3. The evening load shift potential decreases with an increasing utilisation factor. Figure 4.3 shows the peak electricity usage at different production CUs. The peak electricity usage increases with an increase in CU. The load shifting potential is thus low at high CUs.

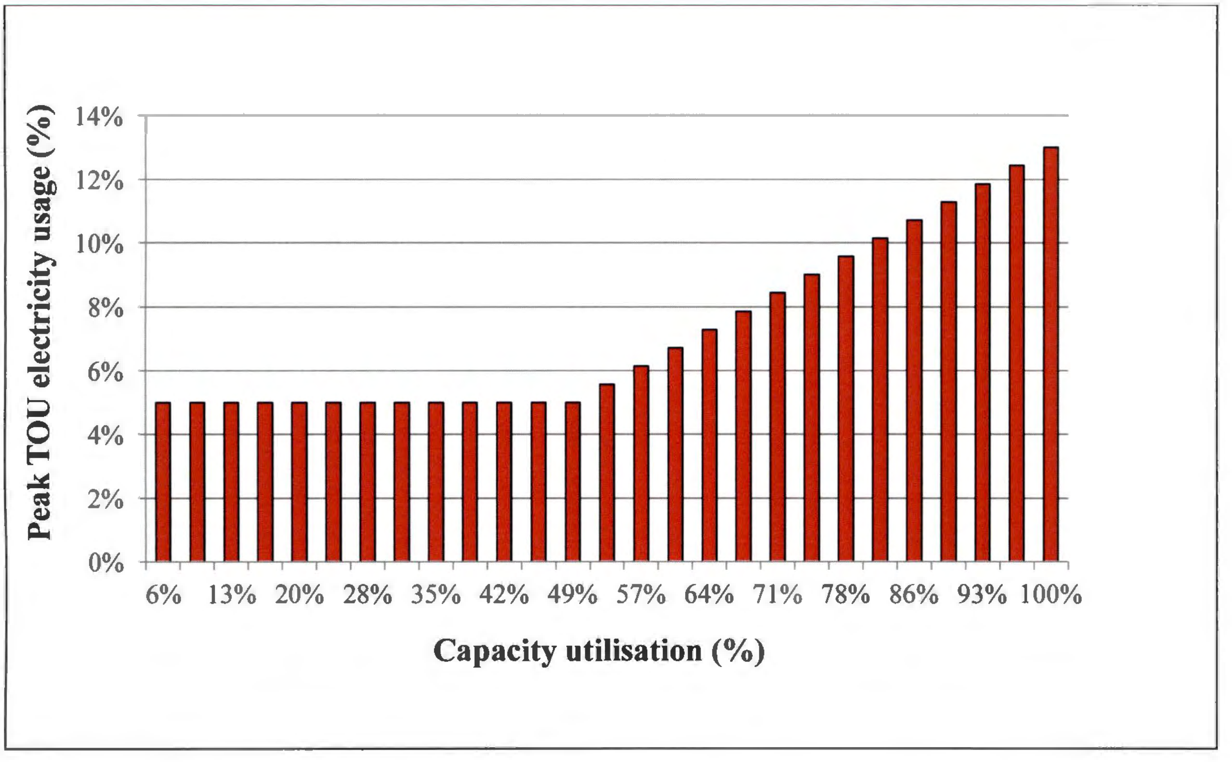

Figure 4.3: Peak TOU electricity usage vs. capacity utilisation

Figure 4.4 shows the load shifting potential for the average plant utilisation of 53% - 57%. The peak electricity usage has decreased significantly whilst the standard and off-peak electricity usages have increased.

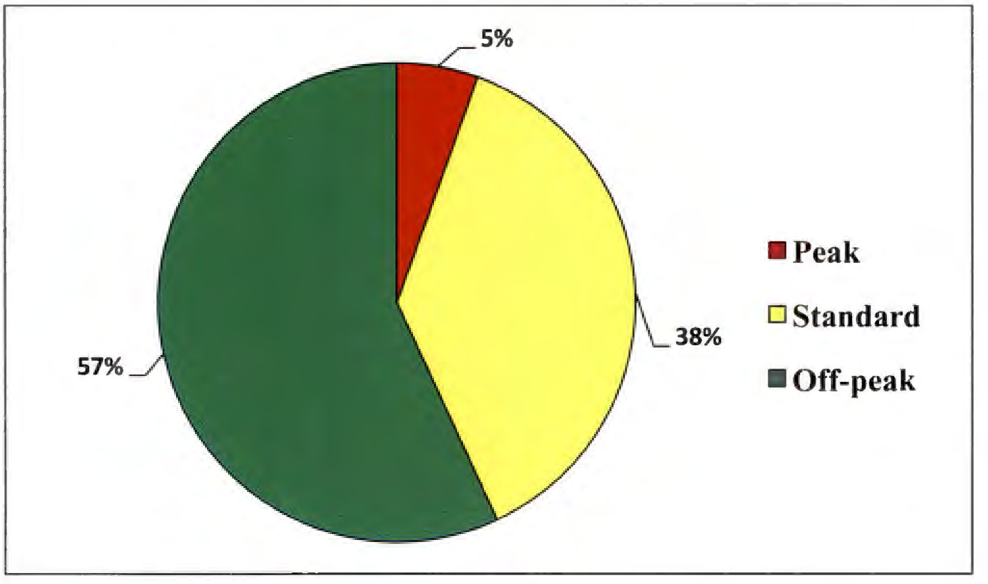

Figure 4.4: Optimised TOU electricity usage

4.2.4 Tariff structure inputs

The plant was initially on the municipal Nightsave tariff. The municipality offered the Megaflex tariff, but due to fluctuating production, the plant was uncertain about changing to the Megaflex tariff. The plant has a special agreement with the municipality and therefore cannot be a direct Eskom customer.

The plant's NMD of 8 650 kVA only allows it to be on the municipal Nightsave or Megaflex tariffs. The two tariffs were thus used in the calculations. The municipal Megaflex and Nightsave tariff charges are given in Table 4.4 and Table 4.5

4.2.5 Simulation results

Scenario 1 - No load shifting

The monthly Nightsave and Megaflex electricity costs were calculated at various production CUs, when no load shifting took place. Figure 4.5 – Figure 4.7 show the Megaflex and Nightsave electricity costs for a summer month, winter month and an annual period respectively.

For the summer month electricity costs, the two tariff costs are almost similar. During the winter months however, the Megaflex electricity costs are less than the Nightsave costs at production CUs of 28% to 95%. The annual electricity costs show a similar pattern to that seen in the winter months. This is because the electricity costs during the winter months are so high that they account for a large percentage of the annual electricity costs.

Table 4.4: 2014/15 Megaflex tariff charges

Charge name	Megaflex charge	Charge unit
High Demand kWh energy–Peak	2.1124	R/kWh
kWh energy–Off-peak	0.3478	R/kWh
kWh energy–Standard	0.6404	R/kWh
Low Demand kWh energy–Peak	0.6896	R/kWh
kWh energy–Off-peak	0.3011	R/kWh
kWh energy–Standard	0.4746	R/kWh
Service charge	140.18	R/day
Admin charge	63.18	R/day
Network demand charge	21.24	R/kVA
Network access charge	11.2	R/kVA
Transmission network charge	5.62	R/kVA
Affordability subsidy	0.0217	R/kWh
Reliability charge	0.0027	R/kWh
Electrification & rural subsidy	0.0546	R/kWh
Reactive energy charge	0.094	R/kVARh

Table 4.5: 2014/15 Nightsave tariff charges

Charge name	Nightsave charge	Charge unit
High Demand kWh Energy	0.4784	R/kWh
kVA Demand	148.78	R/kVA
Low Demand kWh Energy	0.3734	R/kWh
kVA Demand	20.8	R/kVA
Service charge	133.5	R/day
Admin charge	60.17	R/day
Network demand charge	20.23	R/kVA
Network access charge	10.67	R/kVA
Transmission network charge	5.35	R/kVA
Affordability subsidy	0.0207	R/kWh
Reliability charge	0.0026	R/kWh

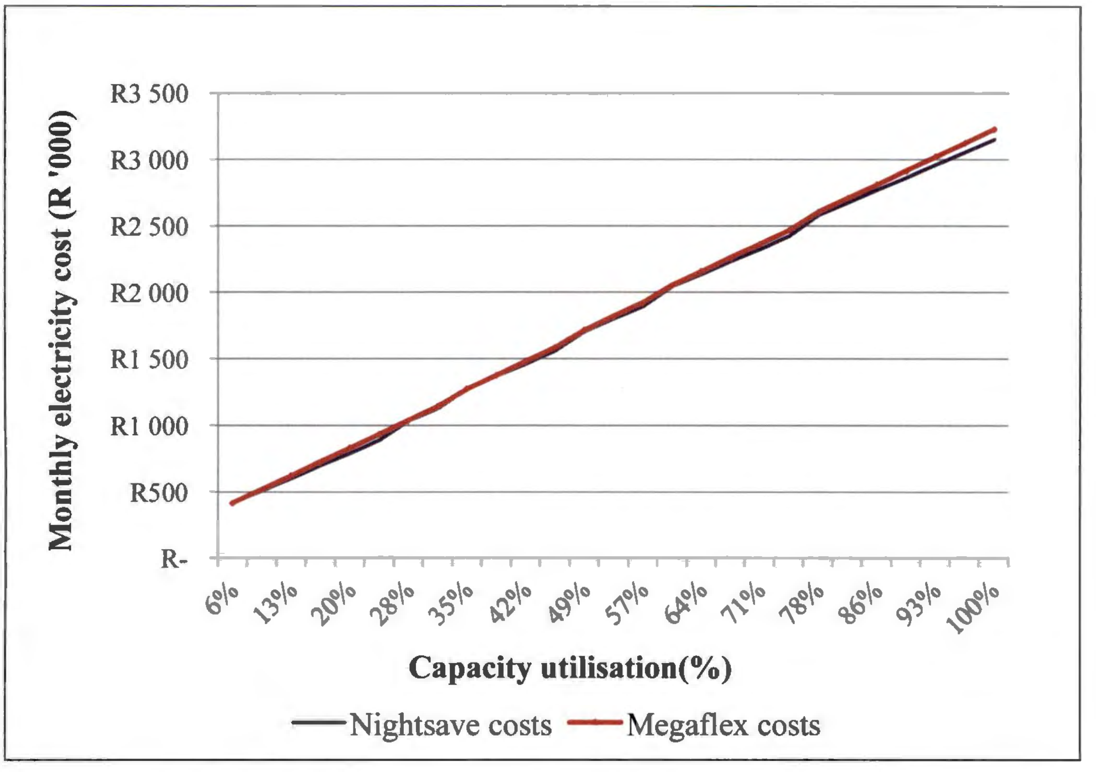

Figure 4.5: Scenario 1-Summer month electricity costs

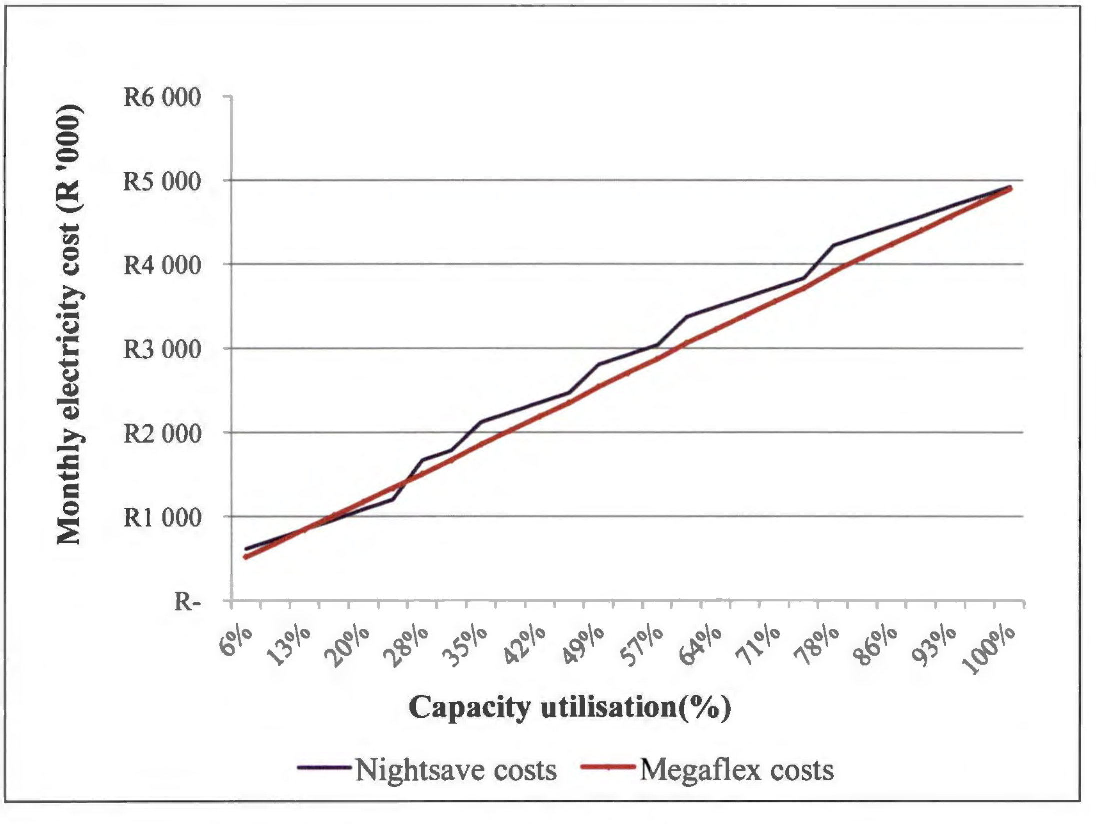

Figure 4.6: Scenario 1-Winter month electricity costs

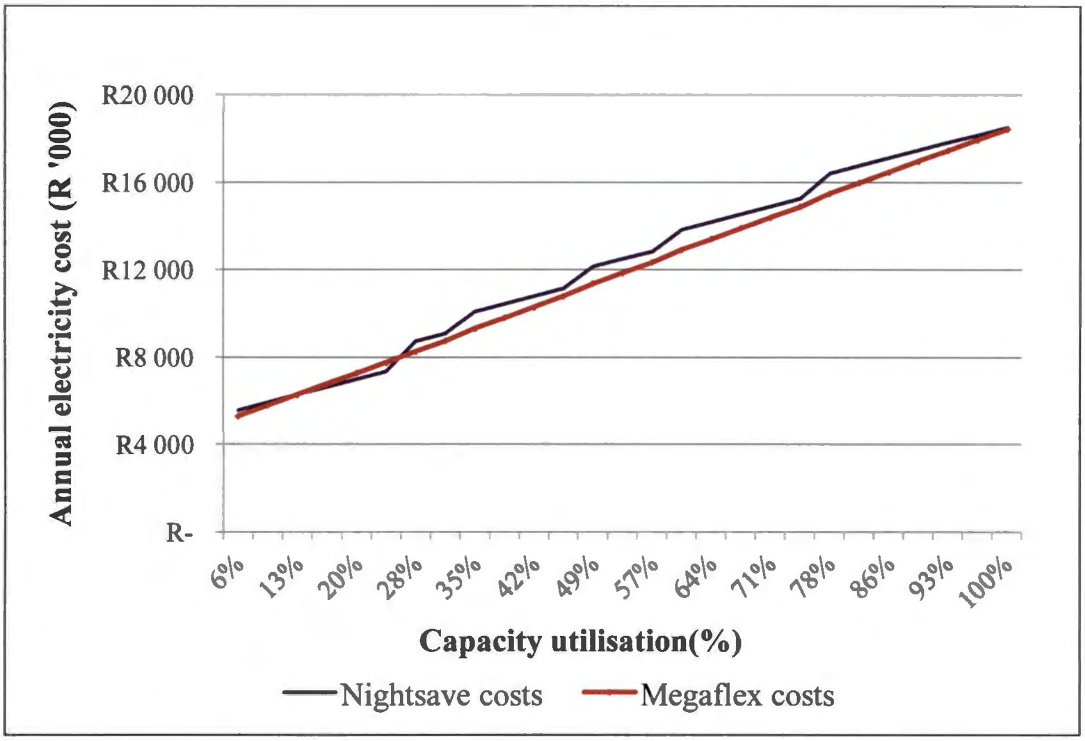

Figure 4.7: Scenario 1-Annual electricity costs

Table 4.6 gives the monthly and annual cost savings at the average plant utilisation of 53% - 57%. In the table it can be seen that the Nightsave tariff has the lowest electricity costs during the summer months. In the winter months however, Megaflex has lower electricity costs.

Table 4.6: Scenario 1 cost savings at 53% - 57% capacity utilisation

	Megaflex (R'000)	**Nightsave (R'000)**	**Cost saving (R'000)**
53% capacity utilisation			
Summer month costs	R 1 816.22	R 1 798.07	R -18.16
Winter month costs	R 2 700.14	R 2 916.05	R 215.91
Annual costs	R 24 446.42	R 24 930.75	R 484.32
Possible electricity cost saving per annum			**2.00%**
57% capacity utilisation			
Summer month costs	R 1 919.80	R 1 892.58	R -27.22
Winter month costs	R 2 863.99	R 3 032.68	R 168.69
Annual costs	R 25 870.20	R 26 131.28	R 261.08
Possible electricity cost saving per annum			**1.00%**

From Figure 4.5 – Figure 4.7 and Table 4.6, it can be seen that though the electricity costs of the Megaflex and Nightsave tariffs are not too different; the Megaflex tariff has slightly lower annual electricity costs at the average CU of 53% - 57%. If the plant were to switch to the Megaflex tariff and not implement load shifting, the plant would only achieve annual cost savings between 1% and 2%.

Scenario 2–Load shifting

The simulation model also calculated the monthly Nightsave and Megaflex electricity costs when load shifting was implemented on the plant. Figure 4.8 – Figure 4.10 show the Megaflex and Nightsave electricity costs for a summer month, winter month and an annual period when load shifting takes place.

During summer months, the Megaflex electricity costs are slightly lower than the Nightsave electricity costs at CUs of 49% - 75%. The winter months and the annual period show that the Megaflex electricity costs are significantly lower than the Nightsave electricity costs.

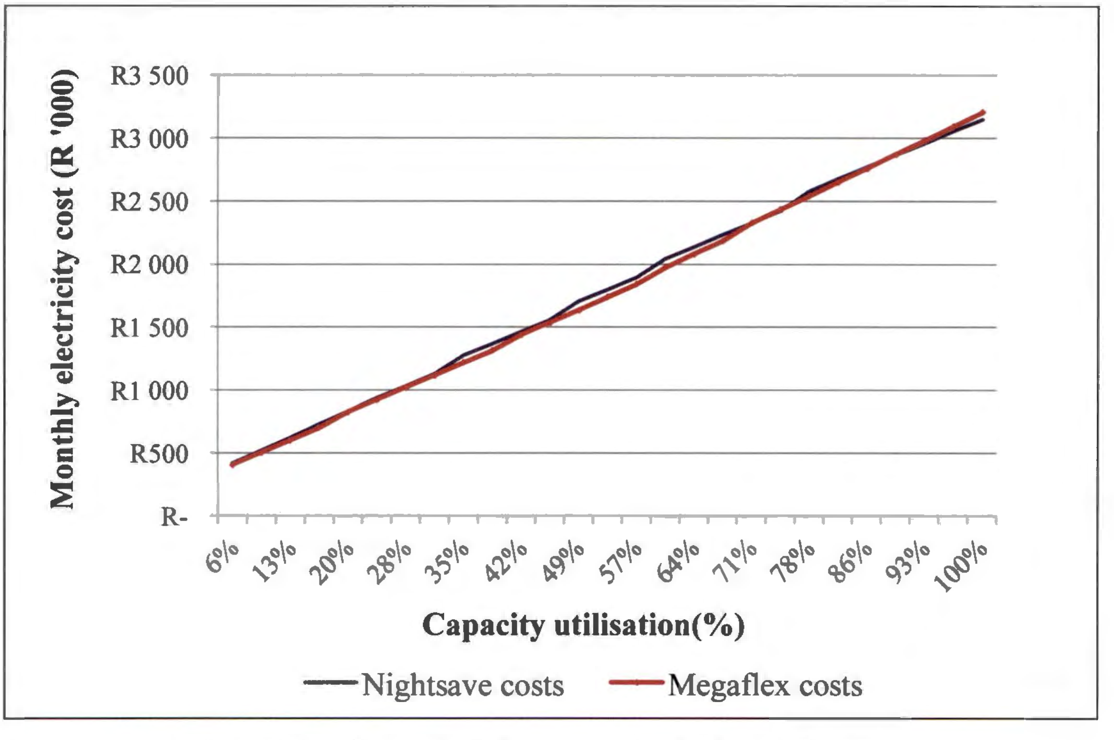

Figure 4.8: Scenario 2-Summer month electricity costs

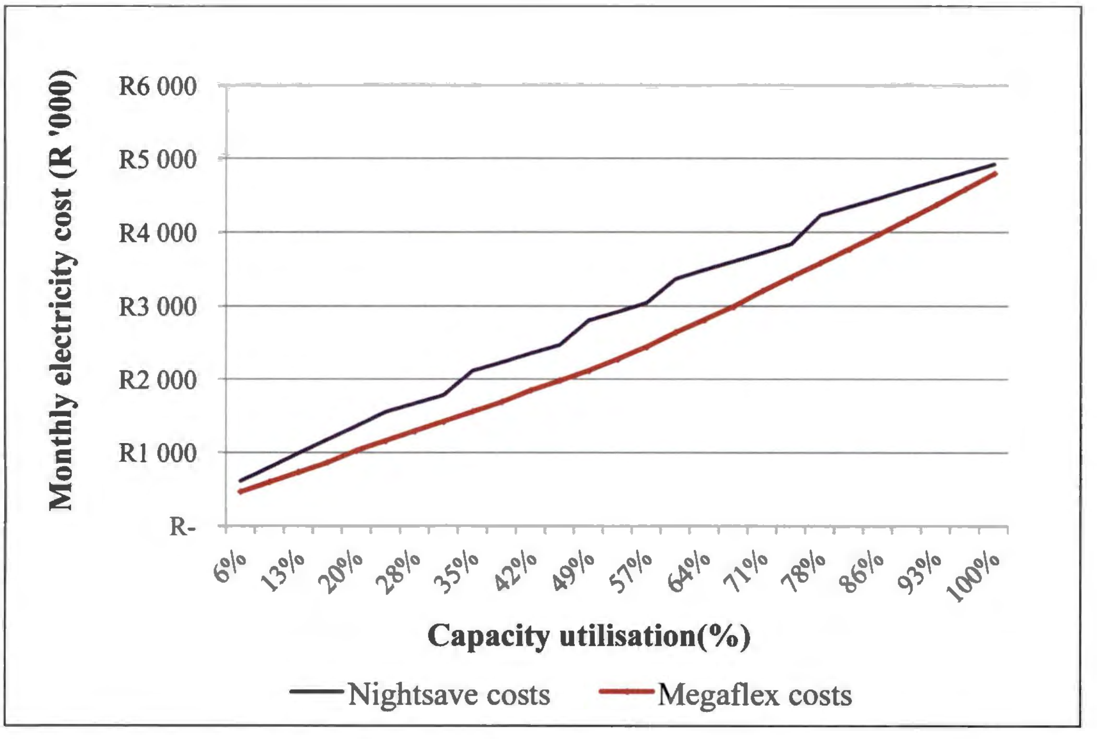

Figure 4.9: Scenario 2-Winter month electricity costs

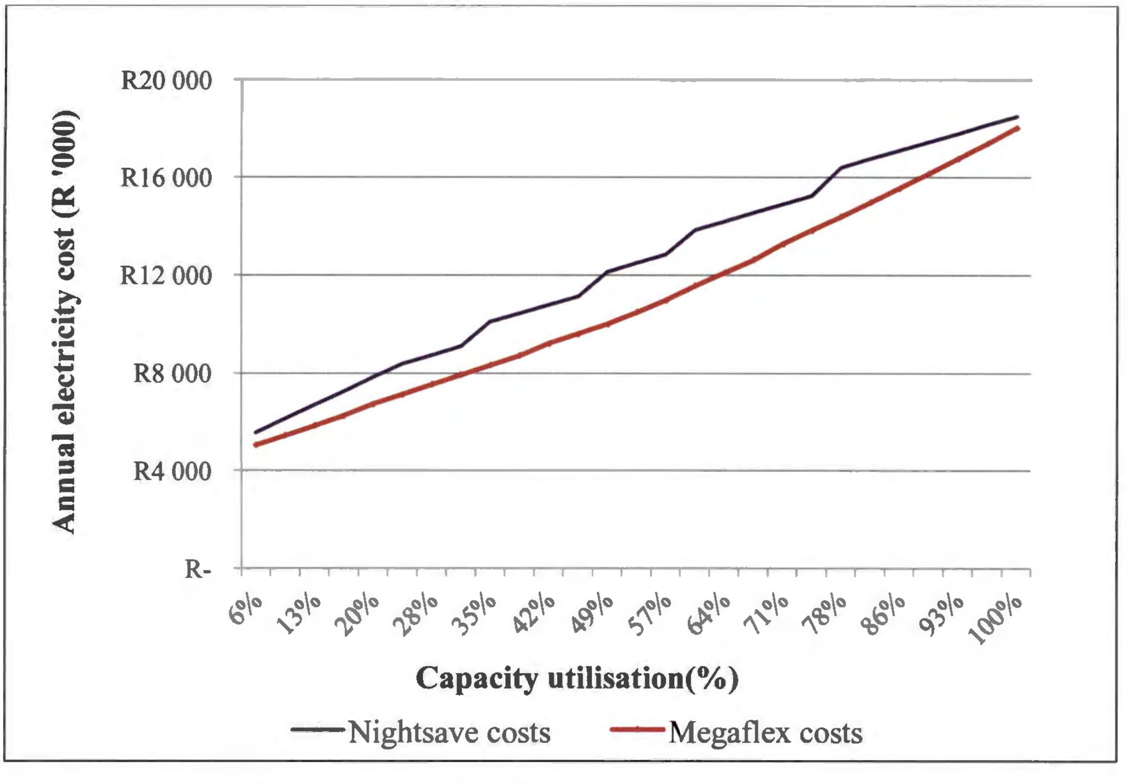

Figure 4.10: Scenario 2-Annual electricity costs

Table 4.7 gives the monthly and annual cost savings at the average plant utilisation factor of 53% - 57% when load shifting is implemented. Megaflex has lower electricity costs during both the summer season and winter season and therefore has less annual electricity costs. An annual cost saving percentage between 9.93% and 10.26% is achievable if load shifting is implemented. From Figure 4.8 – Figure 4.10 and Table 4.7, it can clearly be seen that if load shifting is implemented, significant electricity cost savings can be achieved on the Megaflex tariff.

Table 4.7: Scenario 2 cost savings at 53% - 57% capacity utilisation

	Megaflex (R'000)	**Nightsave (R'000)**	**Cost saving (R'000)**
53% capacity utilisation			
Summer month costs	R 1 735.02	R 1 798.07	R 63.05
Winter month costs	R 2 252.41	R 2 916.05	R 663.64
Annual costs	R 22 372.37	R 24 930.75	R 2 558.37
Possible electricity cost saving per annum			**10.26%**
57% capacity utilisation			
Summer month costs	R 1 833.06	R 1 892.58	R 59.52
Winter month costs	R 2 385.73	R 3 032.68	R 646.95
Annual costs	R 23 654.74	R 26 131.28	R 2 476.55
Possible electricity cost saving per annum			**9.93%**

4.2.6 Selection of tariff structure

From the electricity cost simulations of the two scenarios, it is clear that Megaflex has lower annual electricity costs. If the plant were to switch to the Megaflex tariff, they would achieve electricity cost savings regardless of whether load shifting takes place or not. The implementation of load shifting does however, increase with the implementation of load shifting.

4.2.7 Implementation results

The plant changed to the Megaflex tariff in February 2014 and started implementing load shifting. The implementation results consist of electricity costs and cost savings achieved in twelve consecutive months, starting in February 2014 and ending in January 2015. Months 1-4 and 8-12 were summer months, months 5-7 were winter months. Figure 4.11 shows the CU during each month. The average CU of 53% is also shown.

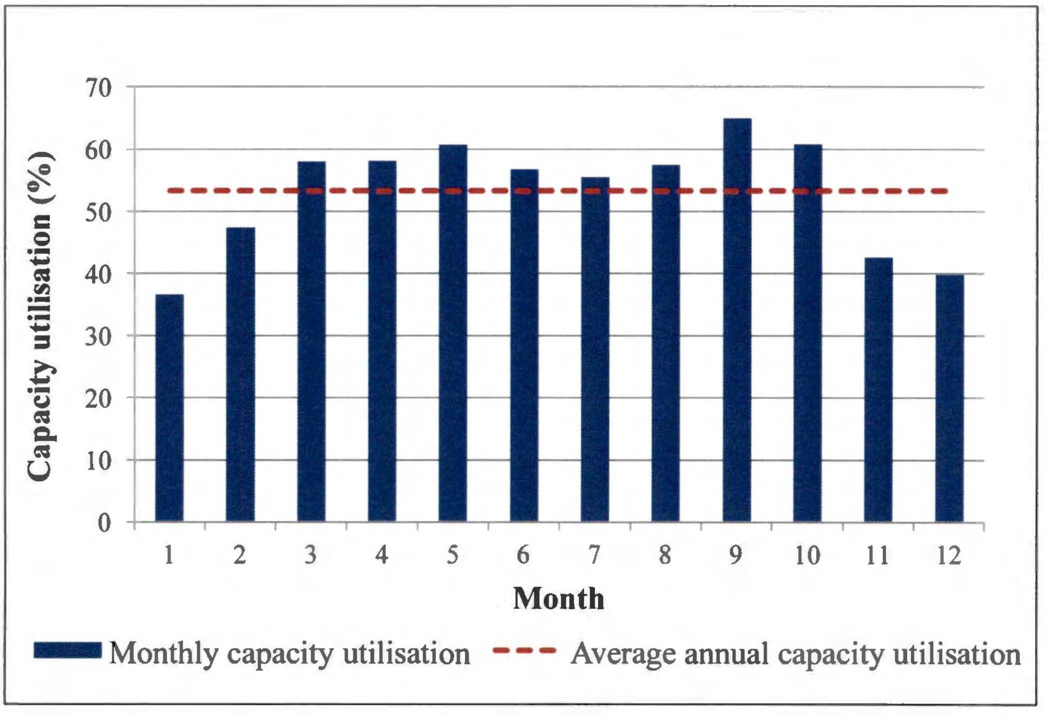

Figure 4.11: Capacity utilisation during implementation period

As previously stated, the plant began implementing load shifting in February 2014. The peak electricity utilisation of the plant for each month is shown in Figure 4.12. The average peak electricity utilisation is also shown. It can be concluded that less load was shifted during months 9 to 11, due to the large peak electricity usage during those months.

Figure 4.14 shows the Megaflex and Nightsave costs for the 12-month period. The graph shows that Megaflex always had lower electricity costs. The Megaflex electricity costs during month 5 to 7 (winter months) are even lower than the Nightsave electricity costs. Figure 4.15 shows the resultant electricity cost savings the plant achieved. The cost savings during the winter months were much higher than the cost savings in the winter months.

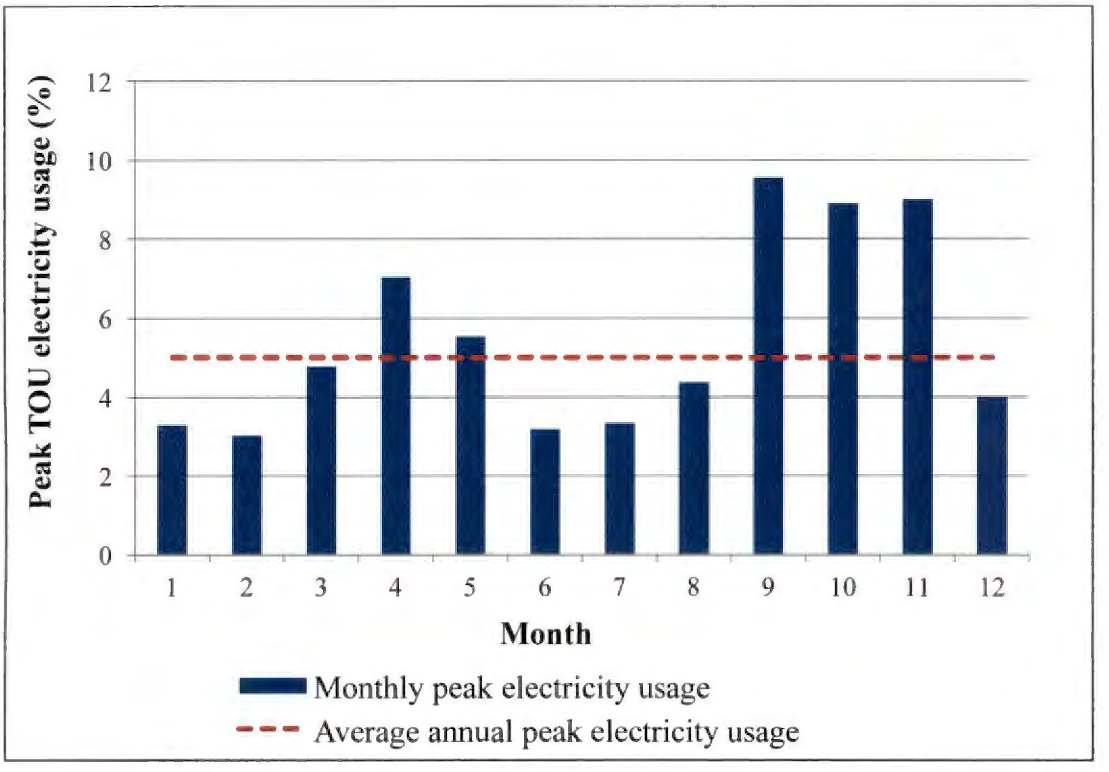

Figure 4.12: Peak TOU electricity usage during implementation period

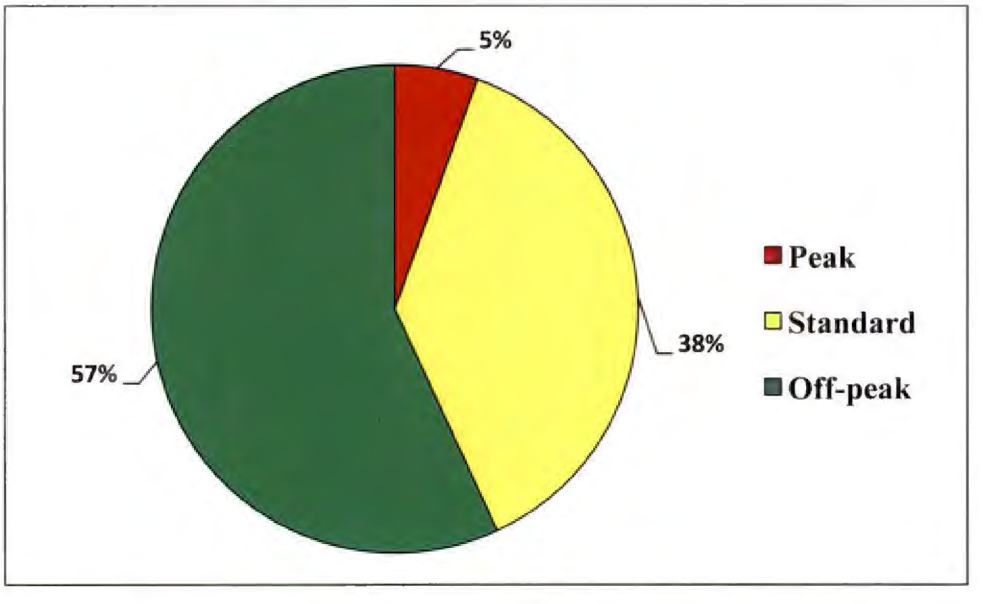

Figure 4.13: Average annual TOU electricity usage during implementation period

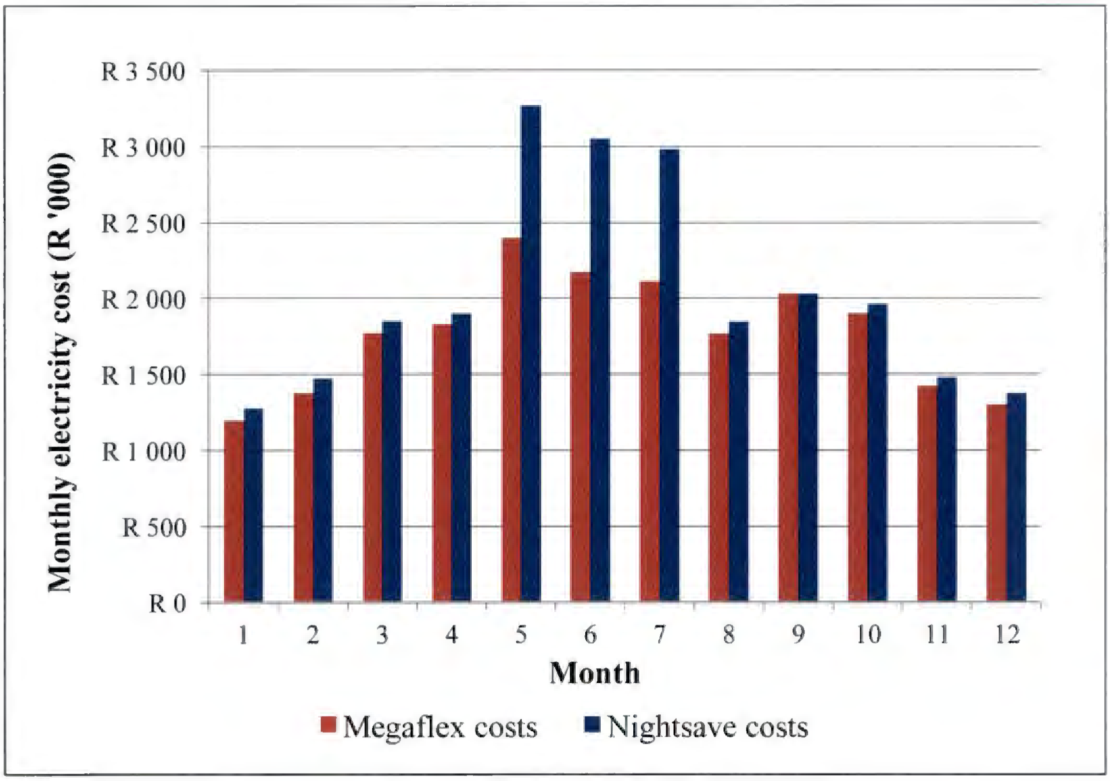

Figure 4.14: Tariff electricity costs during implementation period

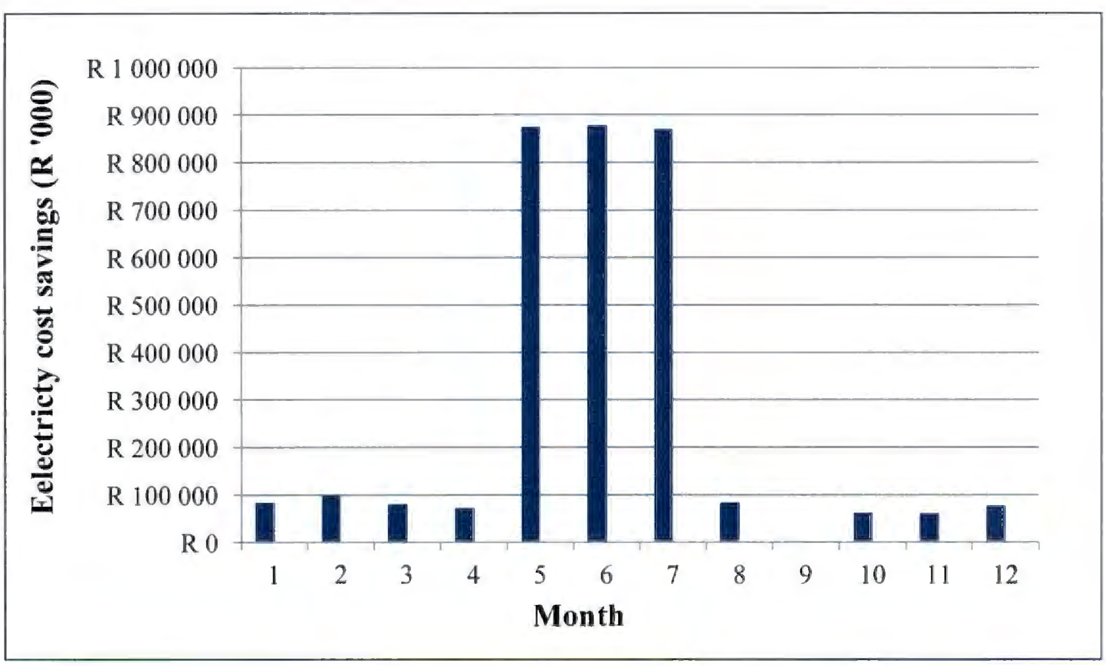

Figure 4.15: Electricity cost savings during implementation period

Table 4.8: Implementation cost savings at 53 % capacity utilisation

	Megaflex (R'000)	**Nightsave (R'000)**	**Cost saving (R'000)**
Summer month costs	R 1 617.66	R 1 685.84	R 68.18
Winter month costs	R 2 224.50	R 3 096.99	R 872.50
Annual costs	R 21 232.43	R 24 463.53	R 3 231.09
Possible electricity cost saving per annum			**13.21%**

4.2.8 Simulated results vs implementation results (Verification of the model)

From the implementation results, it is clear that the model was correct in identifying the tariff structure that would have the lowest cost savings. It is however, necessary to also determine if the simulation model was correct in calculating the cost savings that the plant would achieve. This is done by comparing the cost savings achieved during the implementation period, with the cost savings simulated by the model.

The average CU during implementation was 53%. The implementation cost savings will therefore be compared to the simulated cost savings at the same CU, i.e. 53%. Load shifting took place throughout the implementation period; therefore, the implementation cost savings will be compared to the Scenario 2 simulated cost savings.

Table 4.9 shows the simulated results versus the implementation results. From this comparison, it can be seen that the model was more accurate in predicting the summer cost savings. During the winter months, the implementation cost savings are much higher than the simulated cost savings.

One reason for this significant difference in the winter cost savings is the peak TOU electricity usage during the two of the three winter months. Figure 4.12 shows that though the average annual peak electricity usage is 5%, month 6 and 7 (winter months) have a peak electricity usage of about 3%. The model on the other hand, simulated the cost savings using a peak electricity usage of 5%. As discussed in previous chapters, a low peak electricity usage results in higher cost savings. This would thus explain why the implementation cost savings are higher than the simulated cost savings.

The difference in the annual cost savings is affected as a result of the difference in the winter cost savings. Though the winter and annual cost savings were not as accurate as the summer cost savings, the model still came close in predicting which tariff structure would have the best cost savings.

Table 4.9: Simulated results vs implementation results

	Scenario 2 simulated results	**Implementation results**	**Difference**
Summer month cost savings (R '000)	R 63.05	R 68.18	R 5.13
Winter month cost savings (R '000)	R 663.64	R 872.50	R 208.86
Annual cost savings (R '000)	R 2 558.37	R 3 231.09	R672.72
Annual percentage cost saving	10.26%	13.21%	2.95%

4.3. Case study 2 – Cement process plant

4.3.1 Process plant background and layout

The second case study is a cement manufacturing plant in South Africa. The plant imports clinker via rail and has one mill where the clinker is milled into cement. The plant produces two types of cement, Roadcem and Durabuild. The plant then dispatches the cement product to distributors. Figure 4.16 shows the layout of the cement plant.

4.3.2 Production inputs

Availability and hourly output

The availability and HO of the mill is shown in Table 4.10. The HO of the mill depends on the type of cement that is being produced. For the production of Roadcem, the HO is 155 tonnes/hr and the HO of the mill when Durabuild is being produced is 128 tonnes/hr. The average HO of the mill is used in the calculations.

Table 4.10: Availability and hourly output of the mill

Availability of the mill	Hourly output (tonne/hr) of the mill
0.9	142

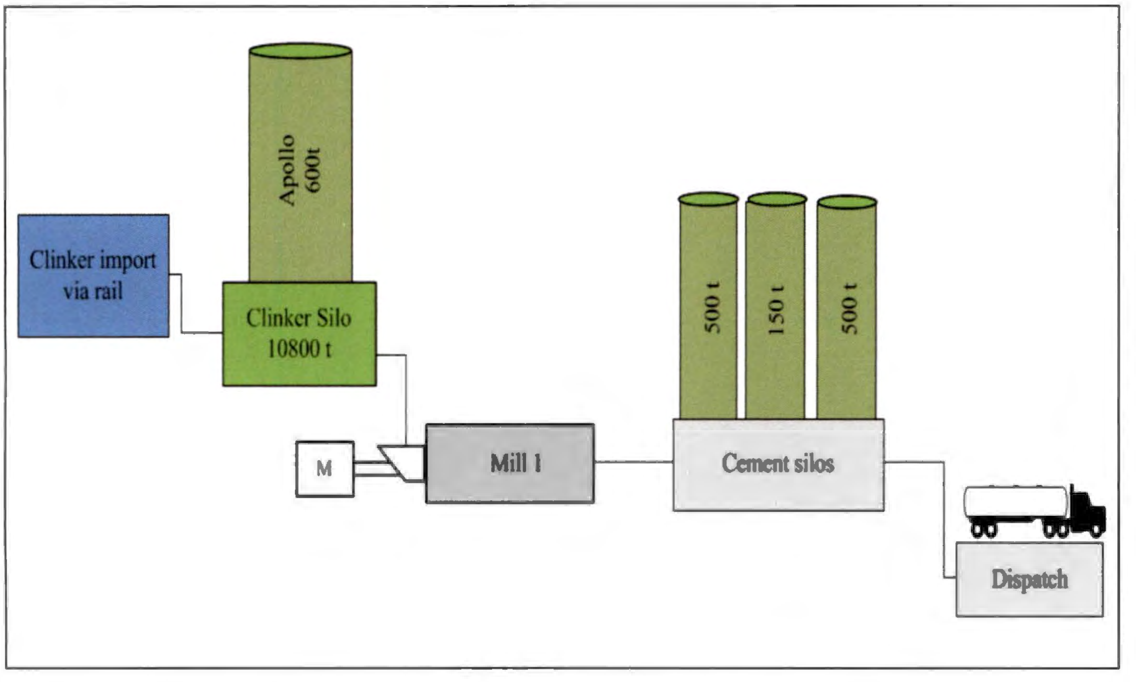

Figure 4.16: Case study two plant layout

Production volume and utilisation

The MPC of the plant was calculated as 95 000 tonnes. The minimum PV is 5 000 tonnes. The average PV of the plant was between 46 000 tonnes and 5000 tonnes. The corresponding utilisation capacity percentages were calculated as indicated in Equation 3.10. Table 4.11 shows the minimum, maximum and average PVs and their corresponding utilisation percentages.

Table 4.11: Production volume and capacity utilisation

	Production volume (tonnes)	Capacity utilisation (%)
Minimum	5 000	5
Average	46 000 – 50 000	49-53
Maximum	95 000	100

4.3.3 Energy inputs

Specific energy consumption and utilised demand

The UD of the plant and the SEC were calculated from historic data. Table 4.12 shows the UD and the SEC of the mill.

Table 4.12: Utilised demand and SEC of the mill

Utilised demand (kVA)	SEC (kWh/tonne)
6335	60

Baseline TOU electricity usage

The baseline electricity usage of the plant is shown in Figure 4.17. Just as seen in the first case study, the peak electricity usage is high. This is due to no load being shifted from the peak TOU periods to the off-peak or standard TOU periods.

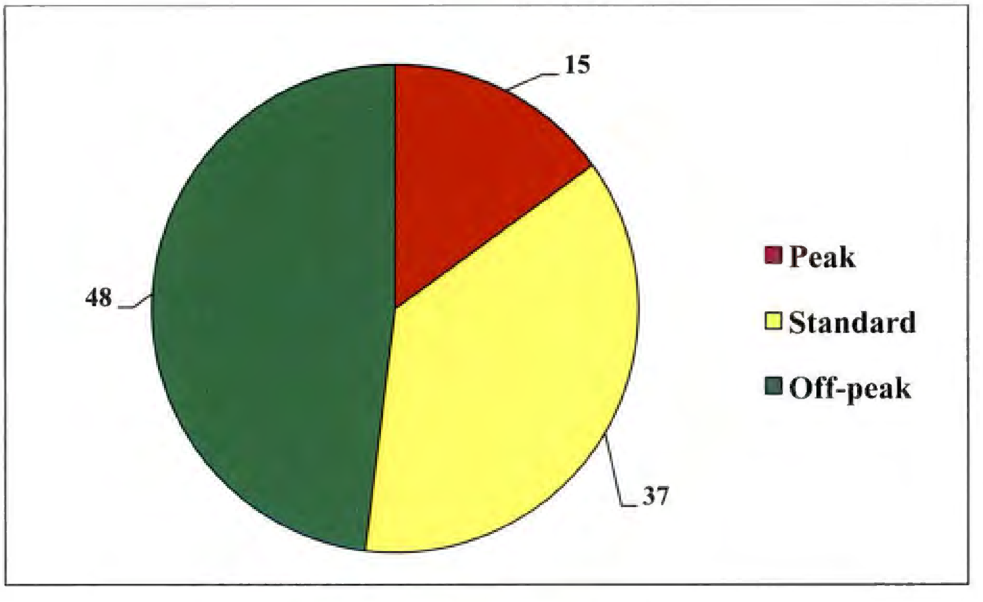

Figure 4.17: Baseline TOU electricity usage

Optimised TOU electricity usage

A simulation was done to determine the optimal peak, standard and off-peak electricity usage at the various CUs. The peak electricity usage at various CUs is shown in Figure 4.18. The peak, standard and off-peak electricity usages at the average utilisation of 49% - 53% are shown in Figure 4.19.

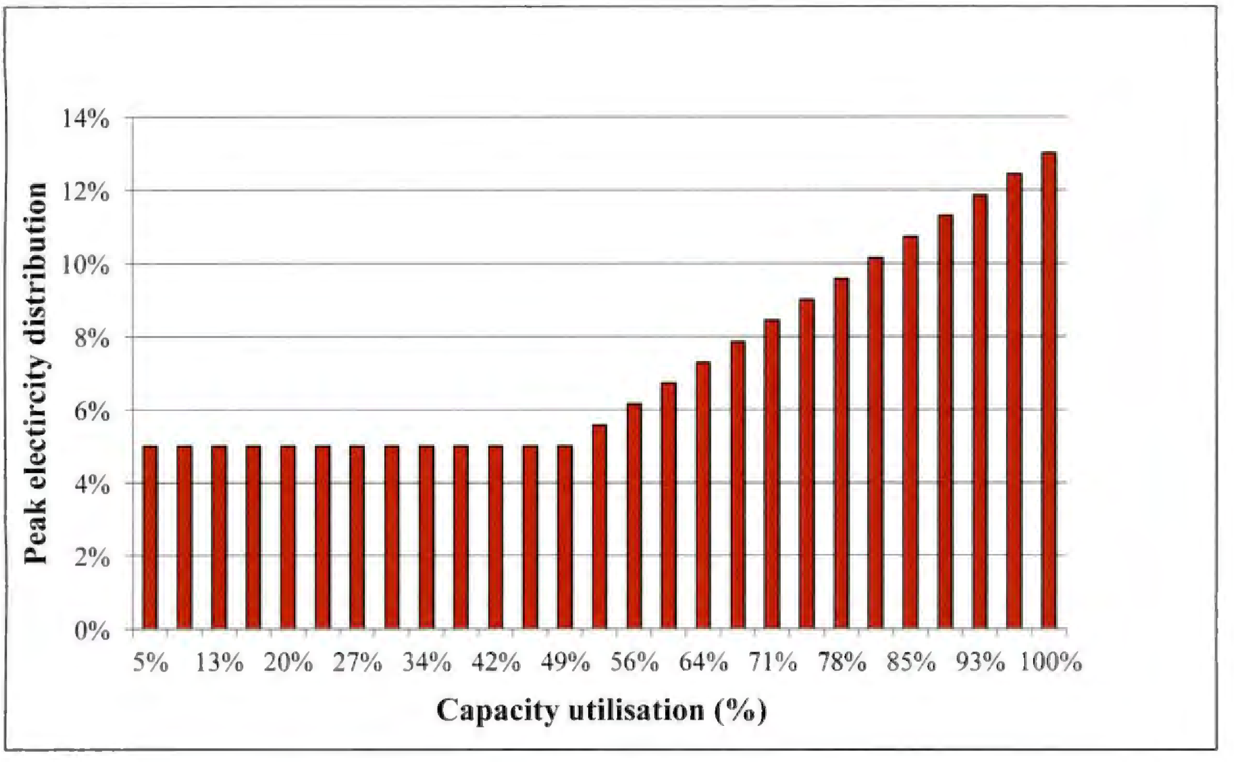

Figure 4.18: Peak TOU electricity usage

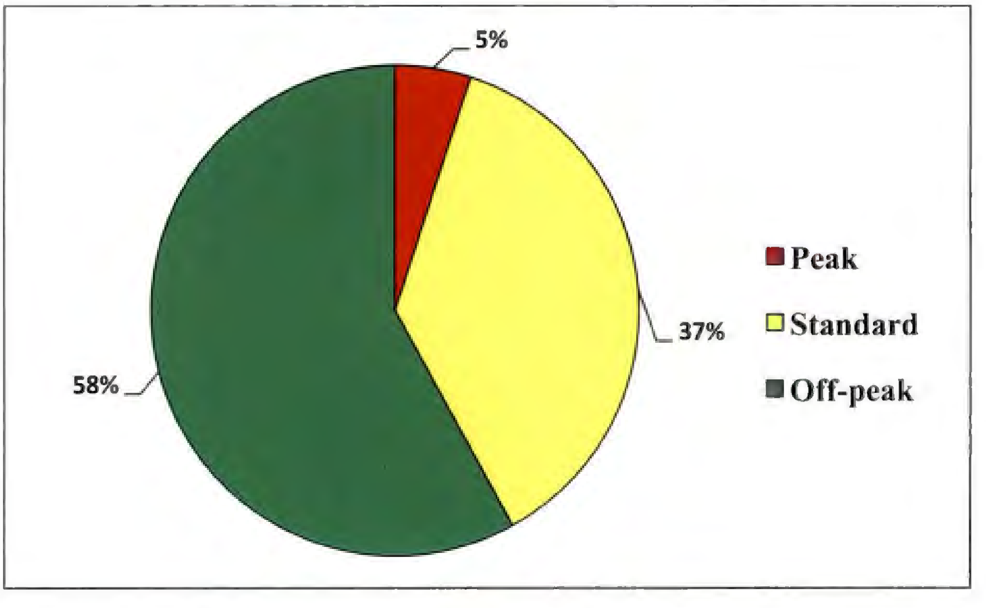

Figure 4.19: Optimised TOU electricity usage

4.3.4 Tariff structure inputs

The cement plant buys electricity from the municipality; they are on the municipality's Business tariff structure. This is a non-TOU tariff structure; the tariff charges stay constant throughout the year. The plant is keen on moving to the Megaflex tariff, but is worried about the costs that may be associated with moving from one tariff structure to another. The charges of the two tariffs are given in Tables 4.13 and 4.14.

Table 4.13: Business tariff charges

Charge name	Business tariff charge	Charge unit
Active energy	0.58	R/kWh
Demand	165.87	R/kVA utilised
Basic/fixed charge	302.35	R/month

Table 4.14: Megaflex tariff charges

Charge name	Megaflex charge	Charge unit
High Demand kWh energy–Peak	2.1124	R/kWh
kWh energy–Off-peak	0.3478	R/kWh
kWh energy–Standard	0.6404	R/kWh
Low Demand kWh energy–Peak	0.6896	R/kWh
kWh energy–Off-peak	0.3011	R/kWh
kWh energy–Standard	0.4746	R/kWh
Service charge	140.18	R/day
Admin charge	63.18	R/day
Network demand charge	21.24	R/kVA utilised
Network access charge	11.2	R/kVA NMD
Transmission network charge	5.62	R/kVA NMD
Affordability subsidy	0.0217	R/kWh
Reliability charge	0.0027	R/kWh
Electrification & rural subsidy	0.0546	R/kWh
Reactive Energy charge	0.094	R/kVARh

4.3.5 Simulation results

Scenario 1 - No load shifting

Equations 3.6 –3.18 in Chapter 3 were used to simulate the monthly electricity costs of the two tariffs at various PVs. Figure 4.21 – Figure 4.23 show the monthly and annual electricity cost for the Megaflex and Business tariff at various utilisation percentages when no load shifting is implemented. The monthly summer costs seen in Figure 4.20 show that Megaflex has lower electricity costs. At higher utilisations, the Megaflex costs are much lower compared to the Business tariff costs.

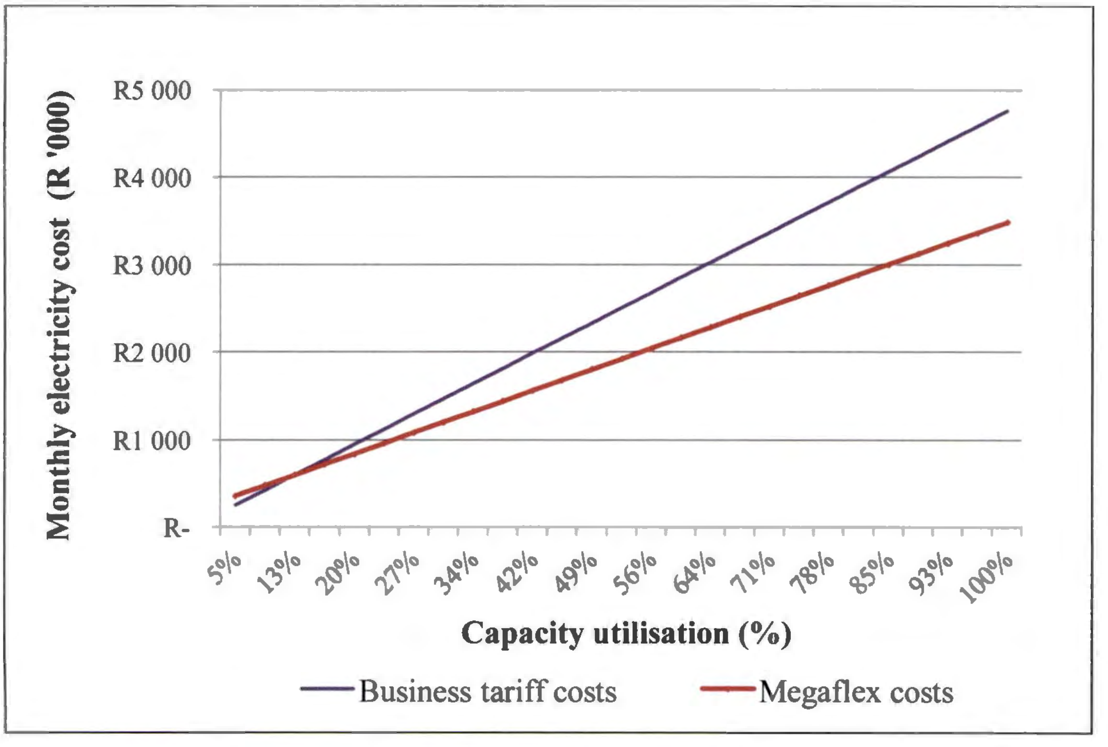

Figure 4.20: Scenario 1-Summer month electricity costs

Figure 4.21 shows the electricity costs during the winter months. During the winter months, the Megaflex tariff has higher costs than the Business tariff. The Megaflex tariff has higher electricity costs at all CUs during the winter months. The electricity costs seen in Figure 4.22 show that the overall annual Megaflex costs are lower than the Business tariff costs. This is due to the fact that the summer costs of the Business tariff are much higher than the Megaflex costs.

Table 4.15 shows the summary of the tariff costs and cost savings at the average CU of 49%-53%. Just as was seen in Figure 4.20 and Figure 4.21, the Business tariff has higher electricity costs during the summer months, but lower electricity costs during the winter months. The annual Megaflex tariff electricity costs are also lower than the annual Business tariff electricity costs. This amounts to a cost saving of 13.02% - 13.55%.

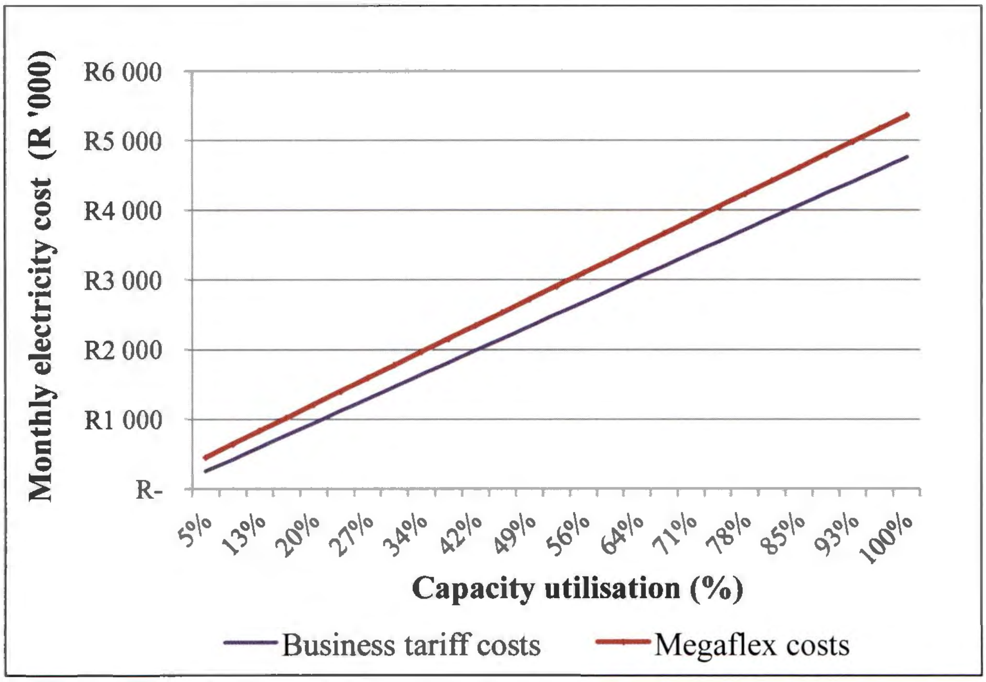

Figure 4.21: Scenario 1-Winter month electricity costs

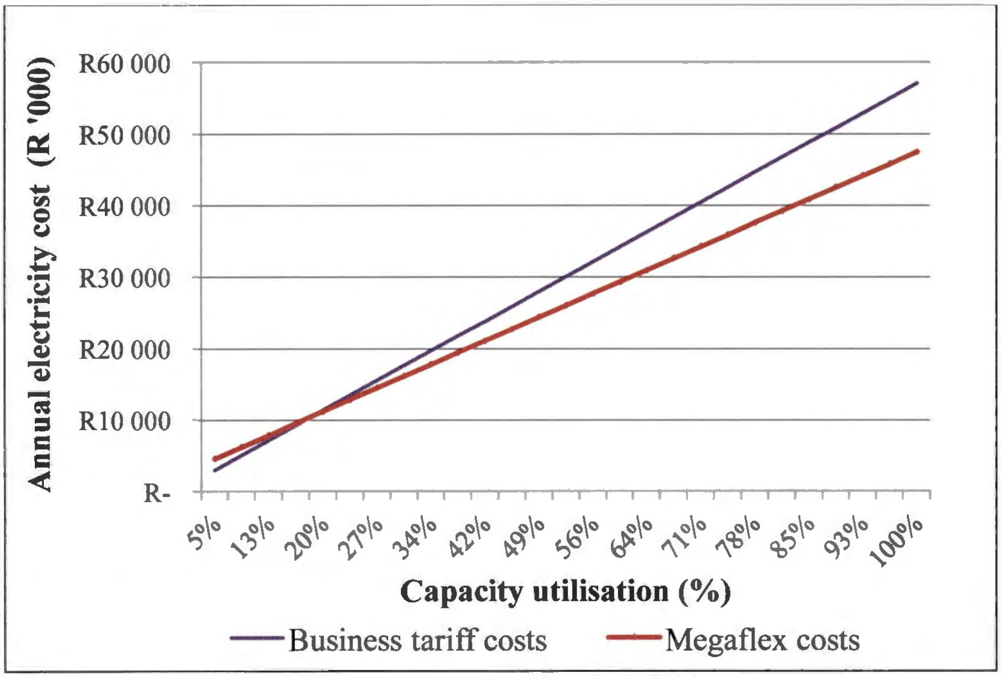

Figure 4.22: Scenario 1-Annual electricity costs

Table 4.15: Scenario 1: Electricity costs savings at 49%-53% capacity utilisation

	Megaflex cost (R'000)	**Business tariff cost (R'000)**	**Cost saving (R'000)**
49% capacity utilisation			
Summer month costs	R 1 794.27	R 2 327.11	R 532.85
Winter month costs	R 2 713.96	R 2 327.11	R -386.85
Annual costs	R 24 290.28	R 27 925.36	R 3 635.08
Possible electricity cost saving per annum			**13.02%**
53% capacity utilisation			
Summer month costs	R 1 914.38	R 2 500.18	R 585.80
Winter month costs	R 2 902.48	R 2 500.18	-R 402.30
Annual costs	R 25 936.84	R 30 002.18	R 4 065.53
Possible electricity cost saving per annum			**13.55%**

Scenario 2 - Load shifting

Figure 4.23 to Figure 4.25 show the monthly and annual electricity costs for Megaflex and the Business tariff structure at various CUs when load shifting is implemented. During the summer months, the cost difference between the two tariff structures is even larger when load shifting is implemented.

Figure 4.24 shows that the costs of the two tariffs are not too different during the winter months. The Megaflex costs are slightly more at low and high CUs and slightly less at average CUs. Figure 4.25 shows that the annual electricity costs of the Megaflex tariff are lower than the Business tariff costs when load shifting takes place.

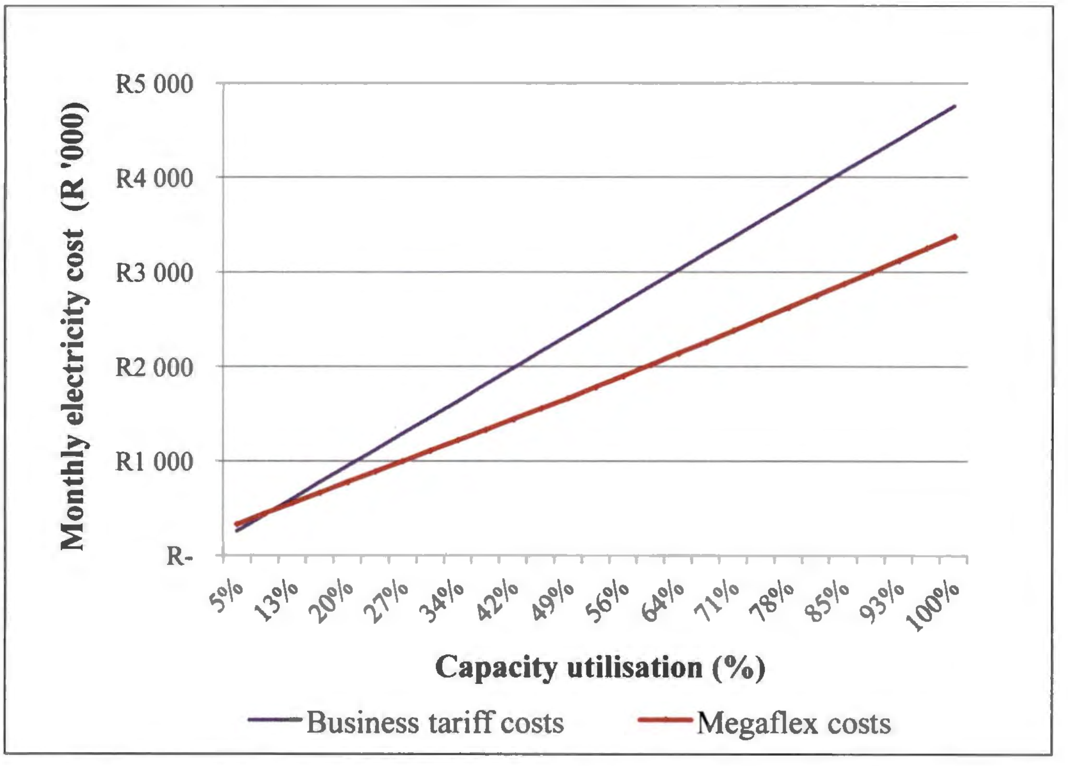

Figure 4.23: Scenario 2-Summer month electricity costs

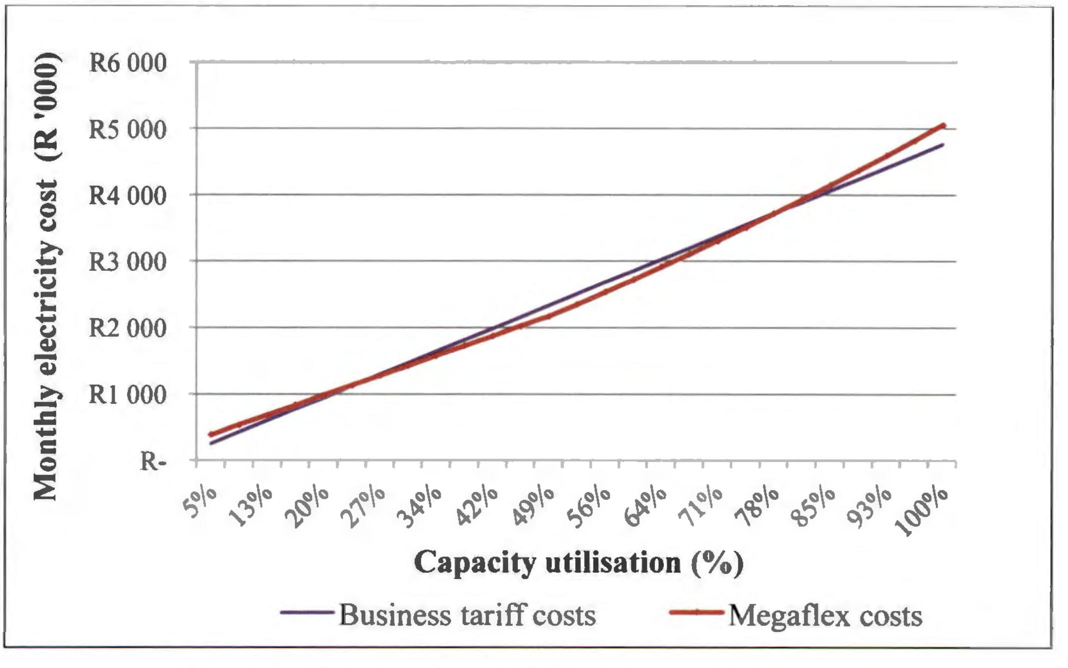

Figure 4.24: Scenario 2-Winter month electricity costs

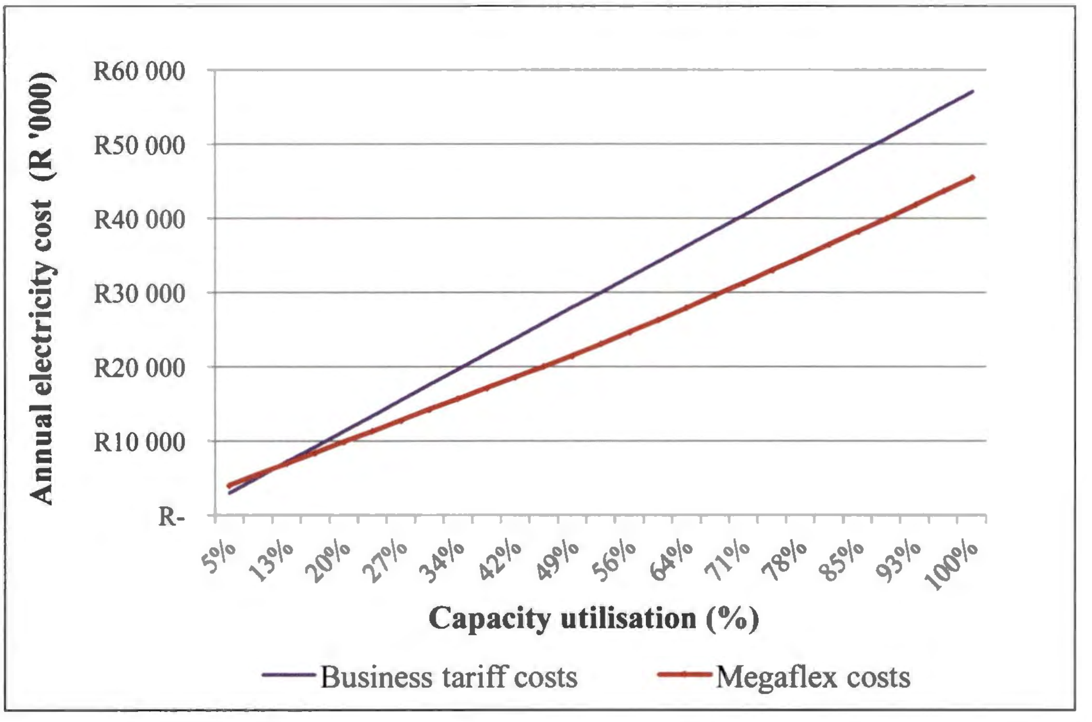

Figure 4.25: Scenario 2-Annual electricity costs

Table 4.16 shows the electricity costs of the two tariff and cost savings at the average CU of 49%-53%. An annual cost saving of 23.23% - 23.24% is achievable if the plant switches from the Business tariff to the Megaflex tariff, and implements load shifting. The reason for this high cost saving is that the Business tariff is not a TOU tariff, and therefore does not afford the plant opportunities to save electricity costs.

4.3.6 Implementation results

The plant is still on the municipality business tariff and is in the process of changing to the Megaflex tariff. Although the plant has not yet changed to the Megaflex tariff structure, it is assumed that the plant will achieve similar results to those simulated above. This assumption can be made on the basis that the model was accurate in simulating the correct cost savings in case study one.

Table 4.16: Scenario 2 – Electricity costs savings at 49%-53% capacity utilisation

	Megaflex (R'000)	**Business tariff cost (R'000)**	**Cost saving (R'000)**
49% capacity utilisation			
Summer month costs	R 1 661.66	R 2 327.11	R 665.46
Winter month costs	R 2 161.48	R 2 327.11	R 165.63
Annual costs	R 21 439.35	R 27 925.36	R 6 486.01
Possible electricity cost saving per annum			**23.23%**
53% capacity utilisation			
Summer month costs	R 1 778.64	R 2 500.18	R 721.54
Winter month costs	R 2 340.18	R 2 500.18	R 160.00
Annual costs	R 23 028.31	R 30 002.18	R 6 937.87
Possible electricity cost saving per annum			**23.24%**

4.4. Conclusion

In this chapter, the simulation model was used to simulate the electricity costs of different tariff structures and thus help process plants to decide which tariff structure was the best for their plants. For case study 1, the simulation showed that the Megaflex was the best tariff structure, due to the lower electricity costs. The Megaflex tariff had even lower electricity costs when load shifting was implemented.

When the plant moved to the Megaflex, the cost savings showed that the Megaflex was the best tariff structure for the plant. The cost savings achieved also showed that the model was accurate in correctly simulating the tariff structure with the lowest electricity costs. The model was also accurate in simulating the summer electricity cost savings that can be achieved if the correct tariff structure is chosen. Due to the simulation model being accurate in the tariff structure selection of case study 1, it is concluded that the Megaflex would also be the best tariff structure for case study 2.

Chapter 5: Conclusion and recommendations

5.1. Overview

In this chapter the final conclusions of the study and recommendations are made. This is done firstly by reviewing the research objectives of the study. The summary of the findings are then discussed. This includes the reviewing of the calculation method and assessing whether the desired results were achieved in Chapter 4. Recommendations of how the study could be improved will be discussed thereafter.

5.2. Review of research objectives

The objective of this study was to design a calculation method that would enable process plants to compare the electricity costs of different tariff structures. The calculation method would be able to show which tariff structure had the lowest cost electricity costs, and thus the best electricity cost savings for the plant. The study would include comparing electricity tariff costs when load shifting was implemented, and when no load shifting took place. Process plants would then be able to make an informed decision before choosing a specific tariff structure.

5.3. Summary of findings

The literature study focused on cement manufacturing and slag milling process plants. During a study of the literature, it was found that there are various tariff structures available for process plants. These tariff structures were designed to be cost reflective and help electricity consumers decrease their electricity costs. A literature study on load shifting opportunities on cement and slag milling plants was also done. It was found that load shifting could also lead to cement and slag milling process plants reducing their electricity costs.

A calculation method that looked at comparing electricity costs of different tariffs at various production capacity utilisations was discussed. The model calculated the electricity costs of various tariffs when load shifting was implemented and when no load shifting was implemented. The model had three sets of inputs; production, energy and tariff structure inputs. These inputs were used to calculate annual electricity costs and the electricity costs during summer months and winter months.

Two case studies were investigated. The first case study was a slag milling plant that was on the Nightsave tariff. The electricity costs of the Nightsave and Megaflex tariffs were simulated using the calculation model. The simulation results showed that large cost savings were achievable if the plant switched to Megaflex tariff and implemented load shifting.

The plant then switched to the Megaflex tariff and implemented load shifting. During the implementation period, the plant saved 13.21% of their electricity cost savings. The implementation results were then compared to the simulated results. The implementation results showed that the model was accurate in predicting the electricity costs during the summer months.

The annual and winter cost savings during implementation were higher than the simulated annual and winter cost savings. This was due to the plant's peak electricity usage being at a lower percentage than the peak percentage calculated by the model. The electricity costs during the winter months showed a high dependence on the peak TOU electricity usage.

The second case study was a cement plant that was on a non-TOU Business tariff. The simulated cost savings showed that a move to the Megaflex tariff would reduce the plant's electricity costs. The electricity costs when would be reduced even more if the plant implemented load shifting.

In the second case study, the move to the Megaflex tariff structure has not yet been made. Due to the model being able to help the first case study choose the correct tariff structure, it is predicted that the implementation results of the second case study will also show a cost saving if the plant moves to the Megaflex tariff.

5.4. Recommendations

The simulated winter cost savings of case study one differed from the implementation winter cost saving due to the different peak electricity usages. It is recommended that a more accurate calculation of the peak electricity usage be done to ensure that the simulated cost savings and the implemented cost savings are equal.

The simulation focused on cement and slag milling plants, in particular, cement plants that only had finishing mills. Though the calculation method can be applied to cement plants that have raw mills and kilns, the calculations would need to be adjusted to accommodate those plants. It is recommended that a further study be done on a complete cement plant in order to ensure that the tariff structures chosen there are also correct.

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Appendix: Electricity tariff costs and savings

Table A1: Case study 1-Scenario 1 summer month electricity costs

CU	Nightsave costs (R '000)	Megaflex costs (R '000)	Cost savings (R '000)
6%	R 414.13	R 414.61	R -0.48
10%	R 508.65	R 518.19	R -9.54
13%	R 603.17	R 621.77	R -18.60
17%	R 697.68	R 725.35	R -27.67
20%	R 792.20	R 828.94	R -36.73
24%	R 886.72	R 932.52	R -45.80
28%	R 1 030.65	R 1 036.10	R -5.45
31%	R 1 125.16	R 1 139.68	R -14.52
35%	R 1 272.58	R 1 270.79	R 1.79
39%	R 1 367.10	R 1 374.37	R -7.27
42%	R 1 461.61	R 1 477.95	R -16.34
46%	R 1 556.13	R 1 581.53	R -25.40
49%	R 1 703.55	R 1 712.64	R -9.09
53%	R 1 798.07	R 1 816.22	R -18.16
57%	R 1 892.58	R 1 919.80	R -27.22
60%	R 2 040.00	R 2 050.91	R -10.91
64%	R 2 134.52	R 2 154.49	R -19.98
67%	R 2 229.03	R 2 258.08	R -29.04
71%	R 2 323.55	R 2 361.66	R -38.11
75%	R 2 418.07	R 2 465.24	R -47.17
78%	R 2 578.71	R 2 603.23	R -24.52
82%	R 2 673.23	R 2 706.81	R -33.58
86%	R 2 767.75	R 2 810.39	R -42.65
89%	R 2 862.26	R 2 913.97	R -51.71
93%	R 2 956.78	R 3 017.55	R -60.78
96%	R 3 051.29	R 3 121.14	R -69.84
100%	R 3 145.81	R 3 224.72	R -78.91

Table A2: Case study 1-Scenario 1 winter month electricity costs

CU	Nightsave costs (R '000)	Megaflex costs (R '000)	Cost savings (R '000)
6%	R 612.15	R 515.06	R 97.10
10%	R 728.78	R 678.90	R 49.88
13%	R 845.41	R 842.75	R 2.66
17%	R 962.04	R 1 006.60	R -44.56
20%	R 1 078.67	R 1 170.45	R -91.78
24%	R 1 195.30	R 1 334.30	R -139.00
28%	R 1 665.43	R 1 498.15	R 167.28
31%	R 1 782.06	R 1 661.99	R 120.06
35%	R 2 115.79	R 1 853.37	R 262.42
39%	R 2 232.42	R 2 017.22	R 215.21
42%	R 2 349.05	R 2 181.07	R 167.99
46%	R 2 465.68	R 2 344.91	R 120.77
49%	R 2 799.42	R 2 536.29	R 263.13
53%	R 2 916.05	R 2 700.14	R 215.91
57%	R 3 032.68	R 2 863.99	R 168.69
60%	R 3 366.42	R 3 055.36	R 311.05
64%	R 3 483.05	R 3 219.21	R 263.83
67%	R 3 599.68	R 3 383.06	R 216.61
71%	R 3 716.30	R 3 546.91	R 169.40
75%	R 3 832.93	R 3 710.76	R 122.18
78%	R 4 220.95	R 3 909.02	R 311.93
82%	R 4 337.58	R 4 072.86	R 264.71
86%	R 4 454.21	R 4 236.71	R 217.50
89%	R 4 570.84	R 4 400.56	R 170.28
93%	R 4 687.47	R 4 564.41	R 123.06
96%	R 4 804.10	R 4 728.26	R 75.84
100%	R 4 920.73	R 4 892.11	R 28.62

Table A3: Case study 1-Scenario 1 annual electricity costs

CU	Nightsave costs (R '000)	Megaflex costs (R '000)	Cost savings (R '000)
6%	R 5 563.68	R 5 276.66	R 97.10
10%	R 5 913.56	R 5 768.20	R 49.88
13%	R 6 263.45	R 6 259.75	R 2.66
17%	R 6 613.34	R 6 751.29	R -44.56
20%	R 6 963.23	R 7 242.84	R -91.78
24%	R 7 313.12	R 7 734.38	R -139.00
28%	R 8 723.50	R 8 225.93	R 167.28
31%	R 9 073.38	R 8 717.47	R 120.06
35%	R 10 074.60	R 9 291.60	R 262.42
39%	R 10 424.48	R 9 783.15	R 215.21
42%	R 10 774.37	R 10 274.69	R 167.99
46%	R 11 124.26	R 10 766.24	R 120.77
49%	R 12 125.47	R 11 340.37	R 263.13
53%	R 12 475.36	R 11 831.91	R 215.91
57%	R 12 825.25	R 12 323.46	R 168.69
60%	R 13 826.46	R 12 897.58	R 311.05
64%	R 14 176.35	R 13 389.13	R 263.83
67%	R 14 526.24	R 13 880.67	R 216.61
71%	R 14 876.13	R 14 372.22	R 169.40
75%	R 15 226.02	R 14 863.76	R 122.18
78%	R 16 390.06	R 15 458.54	R 311.93
82%	R 16 739.95	R 15 950.08	R 264.71
86%	R 17 089.84	R 16 441.63	R 217.50
89%	R 17 439.72	R 16 933.17	R 170.28
93%	R 17 789.61	R 17 424.72	R 123.06
96%	R 18 139.50	R 17 916.26	R 75.84
100%	R 18 489.39	R 18 407.81	R 28.62

Table A4: Case study 1-Scenario 2 summer month electricity costs

CU	Nightsave costs (R '000)	Megaflex costs (R '000)	Cost savings (R '000)
6%	R 414.13	R 404.77	R 9.36
10%	R 518.53	R 502.45	R 16.08
13%	R 622.93	R 600.13	R 22.80
17%	R 727.33	R 697.81	R 29.52
20%	R 831.73	R 823.02	R 8.71
24%	R 936.13	R 920.70	R 15.43
28%	R 1 030.65	R 1 018.38	R 12.27
31%	R 1 125.16	R 1 116.05	R 9.11
35%	R 1 272.58	R 1 213.73	R 58.85
39%	R 1 367.10	R 1 311.41	R 55.69
42%	R 1 461.61	R 1 436.62	R 25.00
46%	R 1 556.13	R 1 534.30	R 21.83
49%	R 1 703.55	R 1 631.98	R 71.57
53%	R 1 798.07	R 1 734.98	R 63.08
57%	R 1 892.58	R 1 838.71	R 53.87
60%	R 2 040.00	R 1 970.70	R 69.30
64%	R 2 134.52	R 2 075.88	R 58.63
67%	R 2 229.03	R 2 181.79	R 47.24
71%	R 2 323.55	R 2 322.84	R 0.71
75%	R 2 418.07	R 2 430.20	R -12.14
78%	R 2 578.71	R 2 538.29	R 40.42
82%	R 2 673.23	R 2 647.11	R 26.12
86%	R 2 767.75	R 2 756.65	R 11.10
89%	R 2 862.26	R 2 866.92	R -4.66
93%	R 2 956.78	R 2 977.91	R -21.13
96%	R 3 051.29	R 3 089.63	R -38.34
100%	R 3 145.81	R 3 202.08	R -56.27

Table A5: Case study 1-Scenario 2 winter month electricity costs

CU	Nightsave costs (R '000)	Megaflex costs (R '000)	Cost savings (R '000)
6%	R 612.15	R 463.10	R 149.06
10%	R 799.48	R 595.77	R 203.72
13%	R 986.81	R 728.44	R 258.37
17%	R 1 174.14	R 861.11	R 313.03
20%	R 1 361.47	R 1 021.31	R 340.16
24%	R 1 548.80	R 1 153.98	R 394.81
28%	R 1 665.43	R 1 286.66	R 378.77
31%	R 1 782.06	R 1 419.33	R 362.73
35%	R 2 115.79	R 1 552.00	R 563.79
39%	R 2 232.42	R 1 684.67	R 547.75
42%	R 2 349.05	R 1 844.87	R 504.18
46%	R 2 465.68	R 1 977.55	R 488.14
49%	R 2 799.42	R 2 110.22	R 689.20
53%	R 2 916.05	R 2 271.62	R 644.43
57%	R 3 032.68	R 2 436.94	R 595.74
60%	R 3 366.42	R 2 633.70	R 732.71
64%	R 3 483.05	R 2 806.86	R 676.19
67%	R 3 599.68	R 2 983.93	R 615.74
71%	R 3 716.30	R 3 199.33	R 516.97
75%	R 3 832.93	R 3 384.24	R 448.70
78%	R 4 220.95	R 3 573.06	R 647.88
82%	R 4 337.58	R 3 765.81	R 571.77
86%	R 4 454.21	R 3 962.47	R 491.74
89%	R 4 570.84	R 4 163.05	R 407.79
93%	R 4 687.47	R 4 367.54	R 319.92
96%	R 4 804.10	R 4 575.96	R 228.14
100%	R 4 920.73	R 4 788.29	R 132.44

Table A6: Case study 1-Scenario 2 annual electricity costs

CU	Nightsave costs (R '000)	Megaflex costs (R '000)	Cost savings (R '000)
6%	R 5 563.68	R 5 032.24	R 149.06
10%	R 6 125.66	R 5 430.26	R 203.72
13%	R 6 687.65	R 5 828.28	R 258.37
17%	R 7 249.63	R 6 226.29	R 313.03
20%	R 7 811.62	R 6 706.89	R 340.16
24%	R 8 373.61	R 7 104.91	R 394.81
28%	R 8 723.50	R 7 502.93	R 378.77
31%	R 9 073.38	R 7 900.94	R 362.73
35%	R 10 074.60	R 8 298.96	R 563.79
39%	R 10 424.48	R 8 696.98	R 547.75
42%	R 10 774.37	R 9 177.58	R 504.18
46%	R 11 124.26	R 9 575.60	R 488.14
49%	R 12 125.47	R 9 973.61	R 689.20
53%	R 12 475.36	R 10 457.82	R 644.43
57%	R 12 825.25	R 10 953.78	R 595.74
60%	R 13 826.46	R 11 544.07	R 732.71
64%	R 14 176.35	R 12 063.53	R 676.19
67%	R 14 526.24	R 12 594.75	R 615.74
71%	R 14 876.13	R 13 240.95	R 516.97
75%	R 15 226.02	R 13 795.68	R 448.70
78%	R 16 390.06	R 14 362.15	R 647.88
82%	R 16 739.95	R 14 940.38	R 571.77
86%	R 17 089.84	R 15 530.36	R 491.74
89%	R 17 439.72	R 16 132.10	R 407.79
93%	R 17 789.61	R 16 745.59	R 319.92
96%	R 18 139.50	R 17 370.83	R 228.14
100%	R 18 489.39	R 18 007.82	R 132.44

Table A7: Case study 2-Scenario 1 summer month electricity costs

CU	Business tariff costs (R '000)	Megaflex costs (R '000)	Cost savings (R '000)
5%	R 250.29	R 352.92	-R 102.63
9%	R 423.36	R 473.03	-R 49.67
13%	R 596.43	R 593.14	R 3.28
16%	R 769.50	R 713.26	R 56.24
20%	R 942.56	R 833.37	R 109.20
23%	R 1 115.63	R 953.48	R 162.15
27%	R 1 288.70	R 1 073.59	R 215.11
31%	R 1 461.77	R 1 193.71	R 268.07
34%	R 1 634.84	R 1 313.82	R 321.02
38%	R 1 807.91	R 1 433.93	R 373.98
42%	R 1 980.98	R 1 554.04	R 426.93
45%	R 2 154.04	R 1 674.15	R 479.89
49%	R 2 327.11	R 1 794.27	R 532.85
53%	R 2 500.18	R 1 914.38	R 585.80
56%	R 2 673.25	R 2 034.49	R 638.76
60%	R 2 846.32	R 2 154.60	R 691.72
64%	R 3 019.39	R 2 274.72	R 744.67
67%	R 3 192.46	R 2 394.83	R 797.63
71%	R 3 365.52	R 2 514.94	R 850.58
74%	R 3 538.59	R 2 635.05	R 903.54
78%	R 3 711.66	R 2 755.17	R 956.50
82%	R 3 884.73	R 2 875.28	R 1 009.45
85%	R 4 057.80	R 2 995.39	R 1 062.41
89%	R 4 230.87	R 3 115.50	R 1 115.36
93%	R 4 403.94	R 3 235.61	R 1 168.32
96%	R 4 577.00	R 3 355.73	R 1 221.28
100%	R 4 750.07	R 3 475.84	R 1 274.23

Table A8: Case study 2-Scenario 1 winter month electricity costs

CU	Business tariff costs (R '000)	Megaflex costs (R '000)	Cost savings (R '000)
5%	R 250.29	R 451.73	R -201.44
9%	R 423.36	R 640.25	R -216.89
13%	R 596.43	R 828.77	R -232.34
16%	R 769.50	R 1 017.29	R -247.79
20%	R 942.56	R 1 205.81	R -263.24
23%	R 1 115.63	R 1 394.32	R -278.69
27%	R 1 288.70	R 1 582.84	R -294.14
31%	R 1 461.77	R 1 771.36	R -309.59
34%	R 1 634.84	R 1 959.88	R -325.04
38%	R 1 807.91	R 2 148.40	R -340.49
42%	R 1 980.98	R 2 336.92	R -355.94
45%	R 2 154.04	R 2 525.44	R -371.40
49%	R 2 327.11	R 2 713.96	R -386.85
53%	R 2 500.18	R 2 902.48	R -402.30
56%	R 2 673.25	R 3 091.00	R -417.75
60%	R 2 846.32	R 3 279.52	R -433.20
64%	R 3 019.39	R 3 468.04	R -448.65
67%	R 3 192.46	R 3 656.55	R -464.10
71%	R 3 365.52	R 3 845.07	R -479.55
74%	R 3 538.59	R 4 033.59	R -495.00
78%	R 3 711.66	R 4 222.11	R -510.45
82%	R 3 884.73	R 4 410.63	R -525.90
85%	R 4 057.80	R 4 599.15	R -541.35
89%	R 4 230.87	R 4 787.67	R -556.80
93%	R 4 403.94	R 4 976.19	R -572.25
96%	R 4 577.00	R 5 164.71	R -587.70
100%	R 4 750.07	R 5 353.23	R -603.15

Table A9: Case study 2-Scenario 1 annual electricity costs

CU	Business tariff costs (R '000)	Megaflex costs (R '000)	Cost savings (R '000)
5%	R 3 003.48	R 4 531.46	R -1 527.97
9%	R 5 080.31	R 6 178.02	R -1 097.72
13%	R 7 157.13	R 7 824.59	R -667.46
16%	R 9 233.95	R 9 471.16	R -237.21
20%	R 11 310.77	R 11 117.73	R 193.05
23%	R 13 387.60	R 12 764.30	R 623.30
27%	R 15 464.42	R 14 410.87	R 1 053.55
31%	R 17 541.24	R 16 057.43	R 1 483.81
34%	R 19 618.07	R 17 704.00	R 1 914.06
38%	R 21 694.89	R 19 350.57	R 2 344.32
42%	R 23 771.71	R 20 997.14	R 2 774.57
45%	R 25 848.53	R 22 643.71	R 3 204.83
49%	R 27 925.36	R 24 290.28	R 3 635.08
53%	R 30 002.18	R 25 936.84	R 4 065.33
56%	R 32 079.00	R 27 583.41	R 4 495.59
60%	R 34 155.82	R 29 229.98	R 4 925.84
64%	R 36 232.65	R 30 876.55	R 5 356.10
67%	R 38 309.47	R 32 523.12	R 5 786.35
71%	R 40 386.29	R 34 169.69	R 6 216.61
74%	R 42 463.12	R 35 816.26	R 6 646.86
78%	R 44 539.94	R 37 462.82	R 7 077.11
82%	R 46 616.76	R 39 109.39	R 7 507.37
85%	R 48 693.58	R 40 755.96	R 7 937.62
89%	R 50 770.41	R 42 402.53	R 8 367.88
93%	R 52 847.23	R 44 049.10	R 8 798.13
96%	R 54 924.05	R 45 695.67	R 9 228.39
100%	R 57 000.87	R 47 342.23	R 9 658.64

Table A10: Case study 2-Scenario 2 summer month electricity costs

CU	Business tariff costs (R '000)	Megaflex costs (R '000)	Cost savings (R '000)
5%	R 250.29	R 324.89	R -74.60
9%	R 423.36	R 436.28	R -12.93
13%	R 596.43	R 547.68	R 48.75
16%	R 769.50	R 659.08	R 110.42
20%	R 942.56	R 770.48	R 172.09
23%	R 1 115.63	R 881.87	R 233.76
27%	R 1 288.70	R 993.27	R 295.43
31%	R 1 461.77	R 1 104.67	R 357.10
34%	R 1 634.84	R 1 216.07	R 418.77
38%	R 1 807.91	R 1 327.46	R 480.44
42%	R 1 980.98	R 1 438.86	R 542.11
45%	R 2 154.04	R 1 550.26	R 603.79
49%	R 2 327.11	R 1 661.66	R 665.46
53%	R 2 500.18	R 1 778.64	R 721.54
56%	R 2 673.25	R 1 896.40	R 776.85
60%	R 2 846.32	R 2 014.93	R 831.39
64%	R 3 019.39	R 2 134.24	R 885.15
67%	R 3 192.46	R 2 254.31	R 938.14
71%	R 3 365.52	R 2 375.17	R 990.36
74%	R 3 538.59	R 2 496.79	R 1 041.80
78%	R 3 711.66	R 2 619.19	R 1 092.47
82%	R 3 884.73	R 2 742.37	R 1 142.37
85%	R 4 057.80	R 2 866.31	R 1 191.49
89%	R 4 230.87	R 2 991.03	R 1 239.84
93%	R 4 403.94	R 3 116.53	R 1 287.41
96%	R 4 577.00	R 3 242.79	R 1 334.21
100%	R 4 750.07	R 3 369.83	R 1 380.24

Table A11: Case study 2-Scenario 2 winter month electricity costs

CU	**Business tariff costs (R '000)**	**Megaflex costs (R '000)**	**Cost savings (R '000)**
5%	R 250.29	R 378.59	R -128.30
9%	R 423.36	R 527.16	R -103.80
13%	R 596.43	R 675.73	R -79.31
16%	R 769.50	R 824.31	R -54.81
20%	R 942.56	R 972.88	R -30.32
23%	R 1 115.63	R 1 121.46	R -5.82
27%	R 1 288.70	R 1 270.03	R 18.67
31%	R 1 461.77	R 1 418.61	R 43.16
34%	R 1 634.84	R 1 567.18	R 67.66
38%	R 1 807.91	R 1 715.76	R 92.15
42%	R 1 980.98	R 1 864.33	R 116.65
45%	R 2 154.04	R 2 012.90	R 141.14
49%	R 2 327.11	R 2 161.48	R 165.63
53%	R 2 500.18	R 2 340.18	R 160.00
56%	R 2 673.25	R 2 523.05	R 150.20
60%	R 2 846.32	R 2 710.10	R 136.22
64%	R 3 019.39	R 2 901.31	R 118.08
67%	R 3 192.46	R 3 096.70	R 95.76
71%	R 3 365.52	R 3 296.25	R 69.27
74%	R 3 538.59	R 3 499.98	R 38.61
78%	R 3 711.66	R 3 707.88	R 3.78
82%	R 3 884.73	R 3 919.96	R -35.23
85%	R 4 057.80	R 4 136.20	R -78.40
89%	R 4 230.87	R 4 356.61	R -125.75
93%	R 4 403.94	R 4 581.20	R -177.26
96%	R 4 577.00	R 4 809.96	R -232.95
100%	R 4 750.07	R 5 042.89	R -292.81

Table A12: Case study 2-Scenario 2 annual electricity costs

CU	Business tariff costs (R '000)	Megaflex costs (R '000)	Cost savings (R '000)
5%	R 3 003.48	R 4 059.74	R -1 056.25
9%	R 5 080.31	R 5 508.04	R -427.73
13%	R 7 157.13	R 6 956.34	R 200.79
16%	R 9 233.95	R 8 404.64	R 829.31
20%	R 11 310.77	R 9 852.94	R 1 457.83
23%	R 13 387.60	R 11 301.24	R 2 086.36
27%	R 15 464.42	R 12 749.54	R 2 714.88
31%	R 17 541.24	R 14 197.84	R 3 343.40
34%	R 19 618.07	R 15 646.14	R 3 971.92
38%	R 21 694.89	R 17 094.45	R 4 600.44
42%	R 23 771.71	R 18 542.75	R 5 228.96
45%	R 25 848.53	R 19 991.05	R 5 857.49
49%	R 27 925.36	R 21 439.35	R 6 486.01
53%	R 30 002.18	R 23 028.31	R 6 973.87
56%	R 32 079.00	R 24 636.75	R 7 442.25
60%	R 34 155.82	R 26 264.67	R 7 891.16
64%	R 36 232.65	R 27 912.06	R 8 320.59
67%	R 38 309.47	R 29 578.92	R 8 730.55
71%	R 40 386.29	R 31 265.27	R 9 121.03
74%	R 42 463.12	R 32 971.09	R 9 492.03
78%	R 44 539.94	R 34 696.38	R 9 843.56
82%	R 46 616.76	R 36 441.16	R 10 175.61
85%	R 48 693.58	R 38 205.40	R 10 488.18
89%	R 50 770.41	R 39 989.13	R 10 781.28
93%	R 52 847.23	R 41 792.33	R 11 054.90
96%	R 54 924.05	R 43 615.01	R 11 309.05
100%	R 57 000.87	R 45 457.16	R 11 543.72