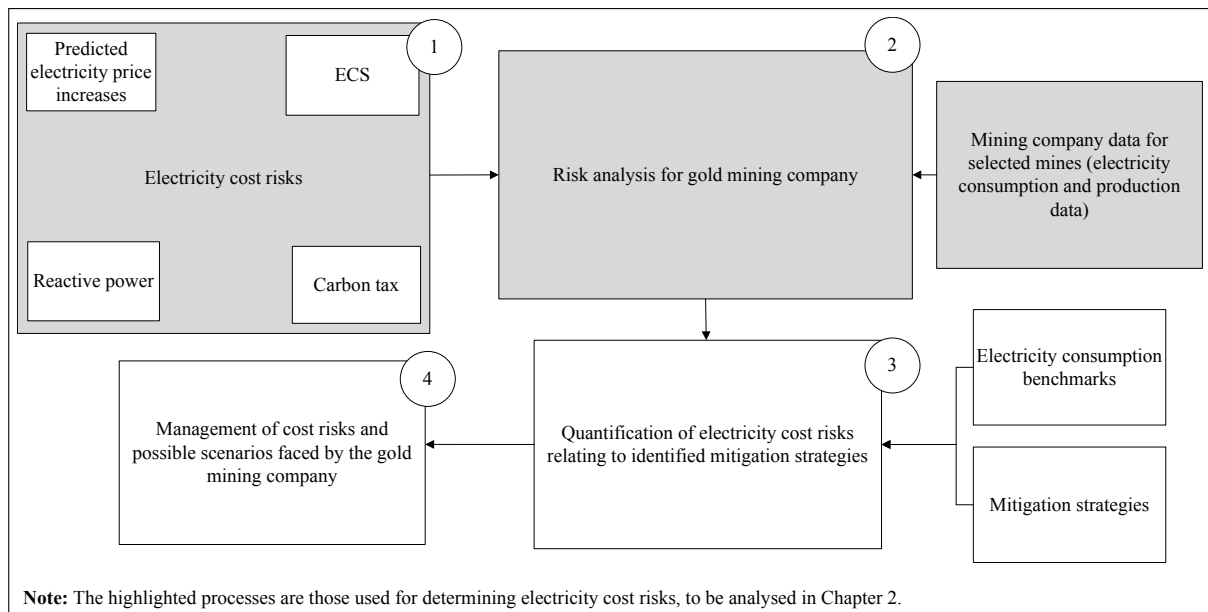


Chapter 2 : Electricity cost risks



2.1 Introduction

There are several uncertainties related to determining electricity costs in the South African gold mining industry. These uncertainties pose a financial risk and must be quantified or modelled to prevent losses from the additional costs that can be predicted. The following sections provide information and quantifying relationships between potential future cost increases, and possible mitigation strategies.

2.2 Power Conservation Programme

2.2.1 Background

The ever-increasing electricity demand and power network inadequacies, with insufficient regional generation sources, pose a great operational risk to South African industries. The Department of Minerals and Energy (DME) therefore required a solution that enabled an increase in the reserve margin to facilitate economic growth and ensure a sustainable electricity supply. As discussed in Chapter 1, rolling blackouts and load shedding which strain the industrial sector should be avoided.

The DME together with Eskom started the National Electricity Response Team (NERT) who then established the Power Conservation Programme (PCP). Previously implemented power rationing models were studied to provide useful insights when designing the PCP [1]. The PCP consists of two subdivisions, namely the Energy Conservation Scheme (ECS) and the Electricity Growth Management (EGM), as illustrated in Figure 2.1.

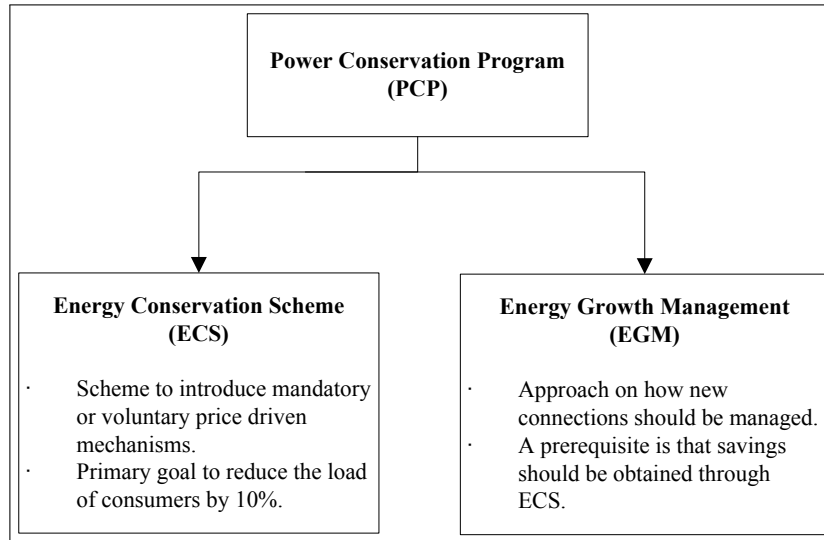


Figure 2.1: Illustration of the two main components of the PCP [2].

EGM mainly focuses on the framework and how new connections or additional loads should be managed. EGM and ECS are directly linked as it is required that electricity is first made available through the ECS programme or other electricity savings programmes before EGM can be implemented. The first available regulation to formulate how the programme is structured was the draft document entitled *Electricity regulations on deviation from approved tariffs* [3].

Several dates were set by the Regulator and it was estimated that the final regulation was to be promulgated and in place by 2009 [4]. However, the latest update is that Eskom is still developing the ECS process and a new consultation draft was presented in 2011 containing the latest ECS rules [5]. There is also no clear indication from Eskom if the ECS will ever be implemented.

The main objective of the ECS scheme is to motivate ECS customers to reduce their electricity consumption by enforcing penalty charges if the customer consumes more electricity than the monthly allocated amount. The ECS procedure aims to induce a lower electricity consumption profile of 10% using selected main consumers or ECS customers.

The presented draft ECS rules consists of several lengthy chapters, which could be overwhelming to mine personnel managing electricity on a daily basis. The main cost-influencing rules of the ECS were thus summarised and simplified according to the presented ECS consultation draft.

This section presents a summary of the main elements that can help model or predict the implications of the ECS. One of the first steps was to create a flow diagram from the summarised ECS procedure. Also from this procedure, the equations used to quantify the selected mining company's ECS penalties were developed. The ECS procedure is described and illustrated with the developed flow charts in the sections below, with the main focus points highlighted.

The main steps in the ECS procedure are:

- Identifying ECS mandatory or voluntary customers.
- Calculation of annual allocated reference consumption.
- Calculation of post-reference loads.
- Identifying investments allocations.
- Calculation of annual electricity allocation and management.
- Calculation of excess electricity usage rates and charges.

The following assumptions were made regarding the ECS procedure:

For the research study, the effects and rules regarding supplementary generation of electricity by the customer have been discarded. Supplementary generation is defined as the electricity generated from generators which are owned or controlled by the mine.

Supplementary generation is not included as the mine company that was analysed only had the installed supplementary generation capacity to facilitate emergency situations and not to support production. The selected mining company will be analysed and seen as a single ECS customer.

The main aspects of the ECS process will be described and throughout the document the following words will correspond to the following definitions [5]:

- “Licensee”: The holder of a license to trade and distribute electricity granted or deemed to have been granted by the Regulator under the electricity act.
- “Customer”: Means the holder or holders of a single electricity account with a licensee at the promulgation date.
- “Regulator”: Means the NERSA.

2.2.2 ECS rule summary

The licensee identifies the main customers that either do consume or forecasts an electricity consumption of more than the prescribed annual threshold amount of 25 GWh. The threshold amount could change from time to time depending on the Regulator. The minister of Energy shall publish savings targets for these customers. The current available savings target for reducing their electricity consumption in the latest review for the mining industry is 10%. The relevant savings target is determined by the Regulator and could vary, being directly linked to South Africa's electrical demand and supply capacity. The electricity allocation in respect to the customer's load is calculated by multiplying confirmed annual post reference consumption with the allocation factor of 0.9.

Reference consumption calculation

One of the crucial tasks of the ECS process is correctly and optimally determining the reference consumption. The reference consumption calculation is performed by using the customer's annual electricity consumption. The reference consumption chosen should be a realistic representation of the electricity consumption and load allocation of the customer.

The summarised process for calculating and selecting the applicable reference consumption is illustrated in Figure 2.2. To create a realistic representation, the customer and the licensee must analyse the hourly electricity consumed over three alternative periods, as described in B.

Once all three reference consumptions for each relevant reference period have been calculated, the customer should then select one of the reference consumptions which would be used to calculate the confirmed annual reference allocation.

The annual post reference consumption for a post reference load is calculated by multiplying the average kWh/day consumption by 365. The value used for the average daily consumption level should be the value representing a stable consumption level, as defined by the ECS rules. The allocation percentage applicable to post reference Energy Efficient Certified (EEC) loads shall be 100% where the allocation percentage applicable to post reference non-EEC loads shall be 90%, for a savings target of 10%.

Investment allocations

A list of qualifying electricity efficiency projects shall be published by the Regulator from time to time. If a customer contributes or implements such an electricity efficient project, the customer will qualify for an annual supplementary allocation, in addition to the reference

allocation. The additional allocation resulting from the electricity savings project will be equivalent to the electrical savings produced by the project.

An incentive will also be available for early completion of qualifying electricity efficient projects. An adjustment factor will be multiplied with the investment allocation. The adjustment factor shall be greater than one and no greater than three, as agreed to by the relevant parties.

Total electricity allocation

Prior to each ECS year, the customer's annual electricity allocation is calculated as follows:

$$A = B + C + D + E \quad (2.1)$$

Where

A = ECS customer's total annual allocation (MWh)

B = ECS customer's annual allocation in respect of reference loads (MWh)

C = ECS customer's annual allocation in respect of post-reference loads (MWh)

D = ECS customer's new connections or additional loads (MWh)

E = ECS customer's investment allocations or adjusted investment allocations (MWh)

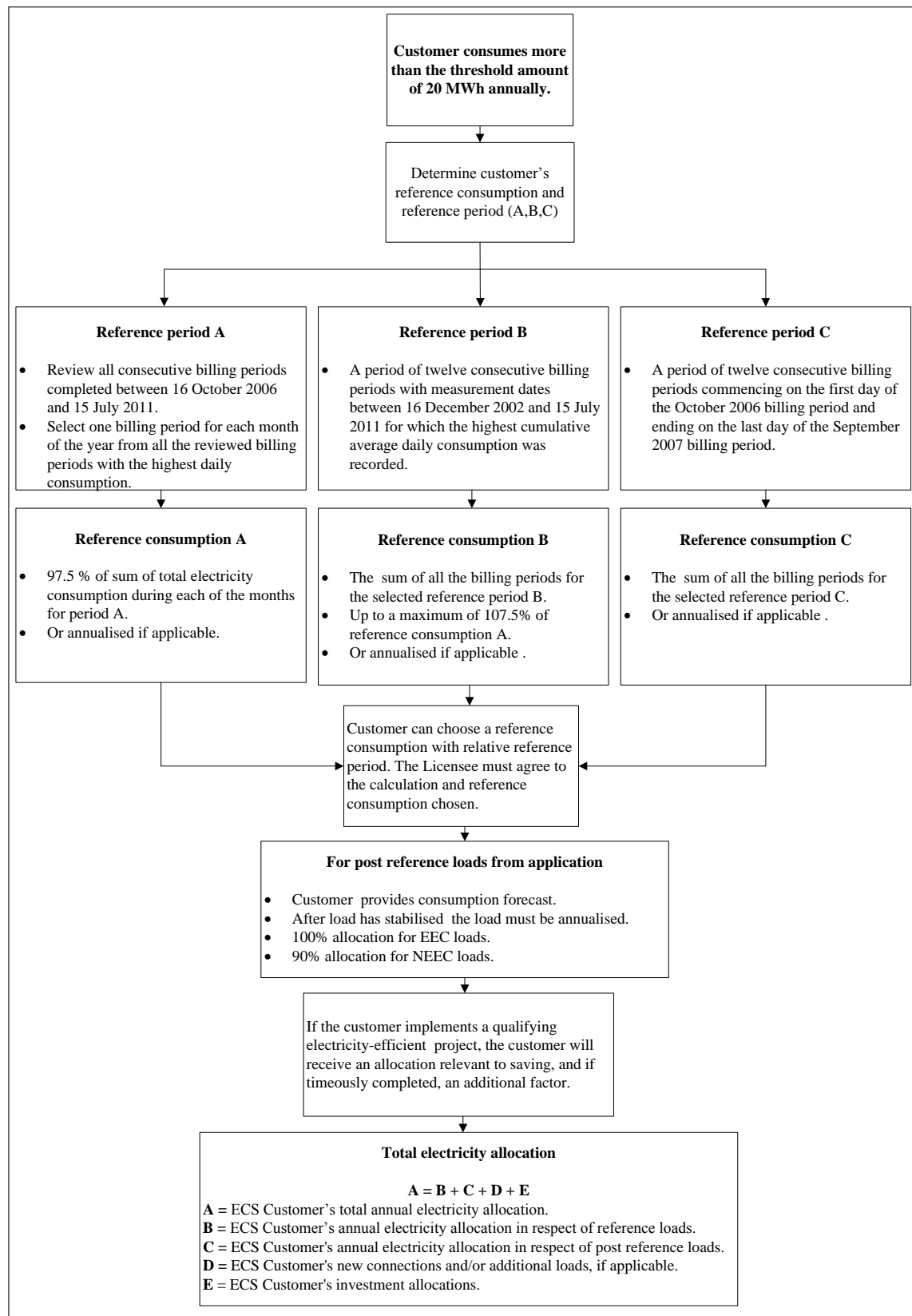


Figure 2.2: ECS total electricity allocation summary [2].

Allocation management

Once the ECS customer receives their annual electricity allocation, there are several additional mechanisms that help the customer to avoid being charged with excess electricity charges throughout the year. These mechanisms will help the customer to rephase and manage monthly electricity allocations, mitigating the risk of excess charges, as summarised in Appendix B.

The allocation, phasing and rephasing process with allocated electricity is illustrated and described in Figure 2.3.

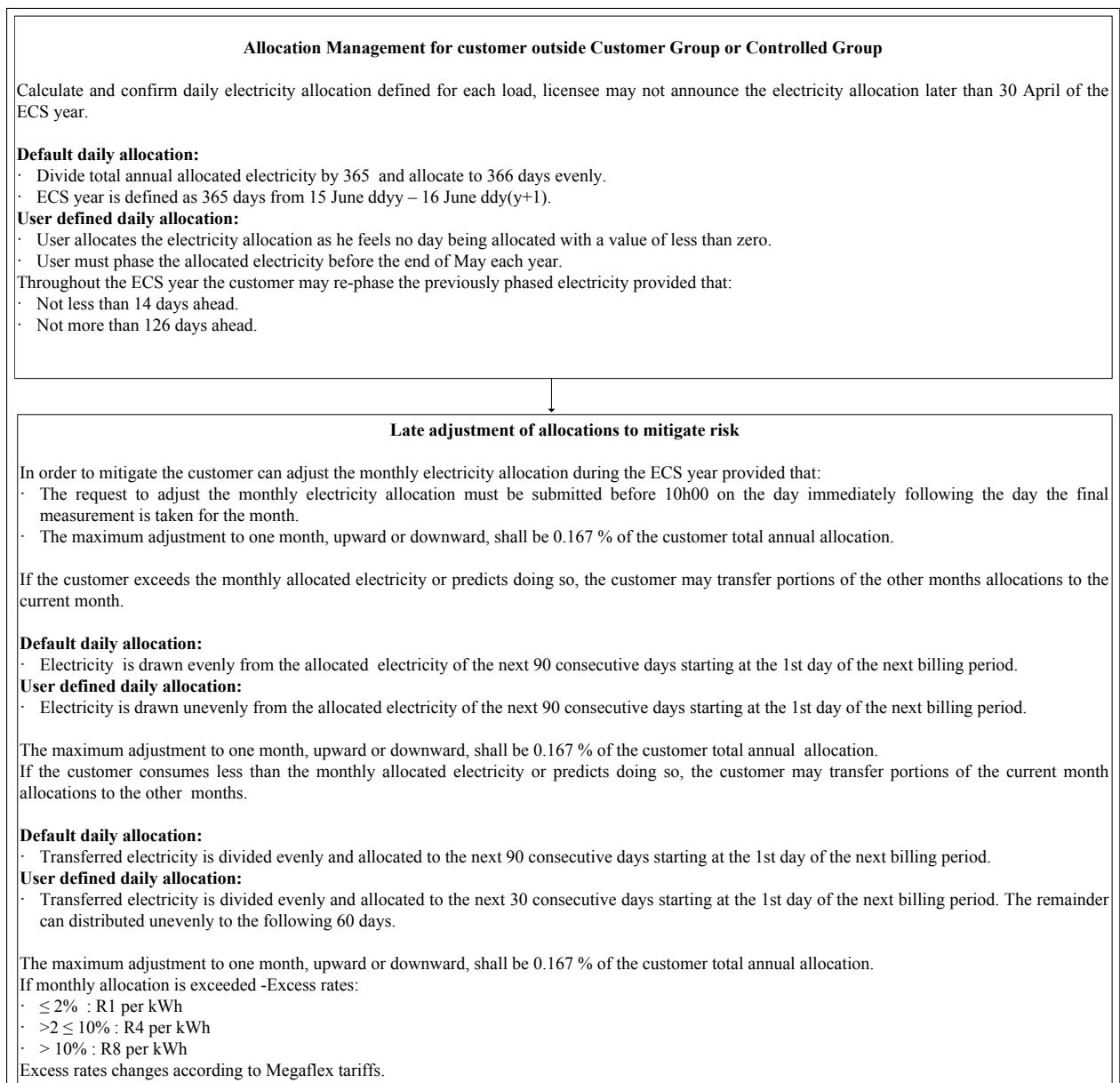


Figure 2.3: ECS allocation management summary [2].

The first step in the management process is the daily allocation of the annual calculated reference allocation. The customer can allocate the total annual allocation according to the

predicted demand profile or use the default allocation. The default allocation is the total annual allocation evenly distributed over the year. The customer must allocate and manage the allocated electricity according to the defined time rules indicated for normal and late adjustments.

For optimal management of electricity supply by the licensee, the ECS customer should, as accurately as possible, ensure that the daily electricity consumption matches that which was forecasted. For additional risk management, the customer may be entitled to adjust the monthly electricity allocation, provided that the request is timely and the amount with which the monthly allocation is adjusted is no more than 0.167% of the customer's annual electricity allocation.

Excess electricity rates and charges

If the ECS rules are approved, the licensee must charge the ECS customer excess electricity charges for consuming more than their final monthly allocation; where these charges are directly related to the degree to which the customer's consumption exceeds the specified monthly allocation. There are three defined levels of exceeding the monthly allocation namely:

Control Band: Where an ECS customer's electricity consumption exceeds its final electricity allocation by up to and including a maximum of 2% of its final monthly electricity allocation, an excess charge of R1 per kWh will be applicable.

Disincentive Band: Where an ECS customer's electricity consumption exceeds its final monthly electricity allocation by more than 2% and up to a maximum of and including 10% of its final monthly electricity allocation, an excess charge of R4 per kWh will be applicable.

Punitive Band: Where an ECS customer's electricity consumption exceeds 10% of its final monthly electricity allocation, an excess charge of R8 per kWh will be applicable.

The excess electricity rates were derived from the total unit cost of producing electricity using a diesel generator having a capacity of between 10 and 20 MW. The value determined according to the derived rate is approximately 25% extra for the Control Band, 100% for the Disincentive Band and 200% for the Punitive Band. The abovementioned tariffs are not fixed and will be subject to change, corresponding with Eskom's Megaflex rates.

If the cumulative electricity consumption of all ECS customers in a group exceeds the allocation value by more than 100.75% for three consecutive months. The Regulator will calculate the average amount by which the cumulative electricity consumption exceeds the 100.75%.

Assessing the amount of consumption that was in the abovementioned bands. If more than 25% to the total excess consumption for the three month period was within one of the abovementioned bands, (Control Band, the Disincentive Band or the Punitive Band) the corresponding excess electricity charges will be multiplied by the adjustment factors listed in Table 2.1. After these adjustment factors are implemented, the adjustments shall remain applied until the Regulator changes the decision.

% Exceed by (Z)	Adjustment Factor
$0.75 < Z \leq 1.5$	1.1
$1.5 < Z \leq 2.5$	1.25
$2.5 < Z \leq 5$	1.5
$Z > 5$	2

Table 2.1: Adjustment factors for corresponding excess electricity charges [2].

2.2.3 Formulating excess electricity rates and charges

The excess rates and charges may vary from month to month depending on the percentage by which the customer exceeds the allocated electricity usage. The ECS rules only stipulate the excess rates according to the provided three bands (Control, Disincentive, and Punitive bands). This could make the interpretation of the expected price increase from the ECS difficult.

To derive a model to help predict the electricity cost risk, the reference consumption and actual consumption were formulated according to the three bands. The aim is to provide the customer with a percentage price increase estimation and to quantify the risks involved with the ECS.

For this study, the following equations were derived to provide the customer with the ability to calculate the percentage increase from the related over consumption.

Assumptions:

The following assumption was made for calculating the predicted monthly price increase:

- The ECS excess rates were released in November 2011 thus 2011/2012 Megaflex rates were used, with an average price of 0.32 R/kWh for low demand months and 0.66 R/kWh during the high demand months.

Control Band:

If the consumption profile of the customer is in the Control Band, then the following equations apply:

$$if : 0 < \left(\frac{C_{ECS} - Rc}{Rc} \right) 100 \leq 2 \quad (2.2)$$

Normal electrical cost would be:

$$E_{Normal} = Tc \times C_{ECS} \quad (2.3)$$

Where the electrical cost for the month including ECS penalties and not consuming more than 2% of the reference consumption:

$$E_{ECS} = Tc \times Rc + CBc(C_{ECS} - Rc) \quad (2.4)$$

Where

C_{ECS} = Total monthly electricity consumed (kWh)

Rc = Reference consumption allocated (kWh)

Tc = Eskom tariff charge (R/kWh)

CBc = ECS Control Band charge (R/kWh)

DBc = ECS Disincentive Band charge (R/kWh)

PBc = ECS Punitive Band charge (R/kWh)

E_{Normal} = Electricity cost without ECS penalties (Rand)

E_{ECS} = Electricity cost with ECS penalties (Rand)

Substituting the values provided for the ECS penalty rates and the average low demand season tariff of R0.32 :

$$E_{Normal} = 0.32 \times C_{ECS} \quad (2.5)$$

$$E_{ECS} = 0.32Rc + 1(C_{ECS} - Rc) \quad (2.6)$$

Maximum Control Band penalties will be charged when the customer consumes 2% more than the reference consumption:

$$E_{ECS \text{ max}} = 0.32Rc + 0.02Rc = 0.34Rc \quad (2.7)$$

$$E_{Normal} = 0.32 \times (1.02Rc) = 0.33Rc \quad (2.8)$$

Comparing the normal electricity monthly price and the maximum electricity cost resulting from Control Band penalties, the customer can expect a price increase of 3% during the low demand months.

Disincentive Band:

If the consumption profile of the consumer is in the Disincentive Band, then the following equations apply:

$$if : 2 < \left(\frac{C_{ECS} - Rc}{Rc} \right) 100 \leq 10 \quad (2.9)$$

Where the electrical cost for the month including ECS penalties and not consuming more than 10% of the reference consumption:

$$E_{ECS} = Tc \times Rc + CBc \times (0.02Rc) + DBc(C_{ECS} - 1.02Rc) \quad (2.10)$$

Substituting the values provided for the ECS penalty rates and the average low demand season tariff of R0.32:

$$E_{ECS} = 0.32Rc + 1(0.02Rc) + 4(C_{ECS} - 1.02Rc) \quad (2.11)$$

Maximum Disincentive Band penalties will be charged when the customer consumes 10% more than the reference consumption:

$$E_{ECS \text{ max}} = 0.66Rc \quad (2.12)$$

$$E_{Normal} = 0.32 \times (1.1Rc) = 0.35Rc \quad (2.13)$$

Comparing the normal electricity monthly price and the maximum electricity cost including the Disincentive Band penalties, the customer can expect an price increase of 89%, during the low demand seasons.

Punitive Band:

If the consumption of the consumer falls only in the Punitive Band, then the following equations apply:

$$\left(\frac{C_{ECS} - Rc}{Rc}\right) > 10 \quad (2.14)$$

Where the electrical cost for the month including ECS penalties and consuming more than 10% of the reference consumption:

$$E_{ECS} = Tc \times Rc + CBc \times (0.02Rc) + DBc(0.08Rc) + PBc(C_{ECS} - 1.1Rc) \quad (2.15)$$

Substituting the values provided for the ECS penalty rates and the average low demand season tariff of R0.32:

$$E_{ECS} = 0.32Rc + 1(0.02Rc) + 4(0.08Rc) + 8(C_{ECS} - 1.1Rc) \quad (2.16)$$

For this example, the maximum Punitive Band penalties will be added when the customer consumes 15% more than the reference consumption:

$$E_{ECS(15\%)} = 1.06Rc \quad (2.17)$$

$$E_{Normal} = 0.32 \times (1.15Rc) = 0.37Rc \quad (2.18)$$

Comparing the normal electricity monthly price and the maximum electricity cost involved with Punitive Band penalties, the customer can expect an price increase of 186% when consuming 15% more than the reference consumption negotiated.

From the equations above, a graph was derived which could be used to estimated the price increase in relation to the percentage over consumed. The derived ECS cost increase graph is illustrated in Figure 2.4.

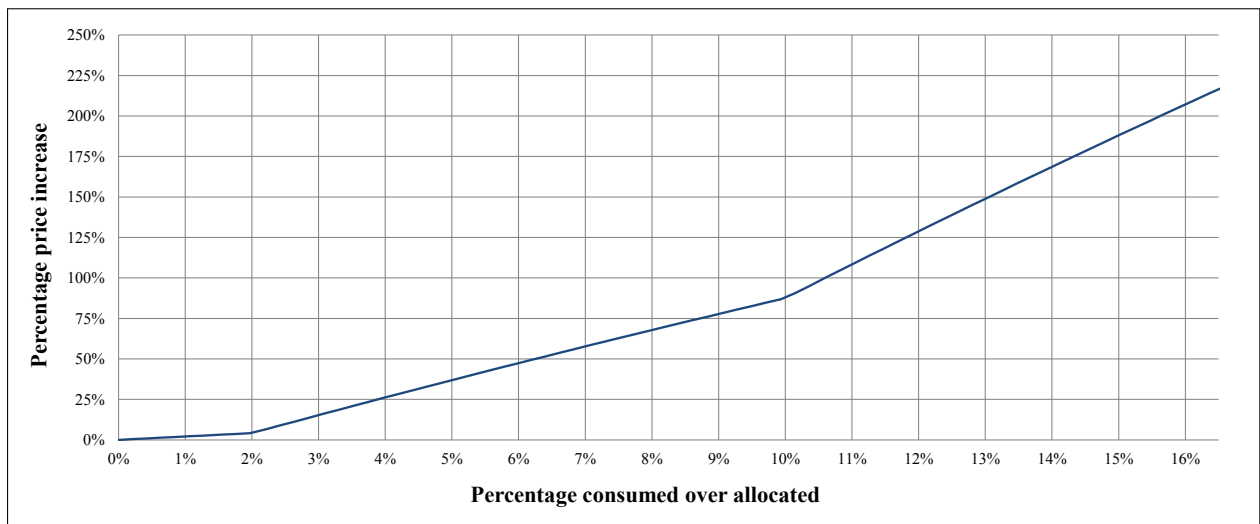


Figure 2.4: Percentage electricity cost increase relative to the percentage over consumption.

2.2.4 ECS cost risk scenarios

To illustrate the potential cost risk involved with ECS, three scenarios were derived and discussed below. For the presented scenarios, the actual electricity consumption during 2010 of this mining company was used and compared to a negotiated reference consumption by the mine and Eskom. The mine managed to reduce their electricity consumption by 3% in comparison to the reference consumption of 2007.

The first scenario illustrates what would have happened if the monthly electricity was allocated by default and no phasing was performed by the mining company. Scenario one in Figure 2.5 indicates that additional ECS charges could have resulted in an annual price increase of 50%. Electricity should be dynamically allocated to avoid unforeseen electricity costs during high demand seasons when the electricity prices are higher.

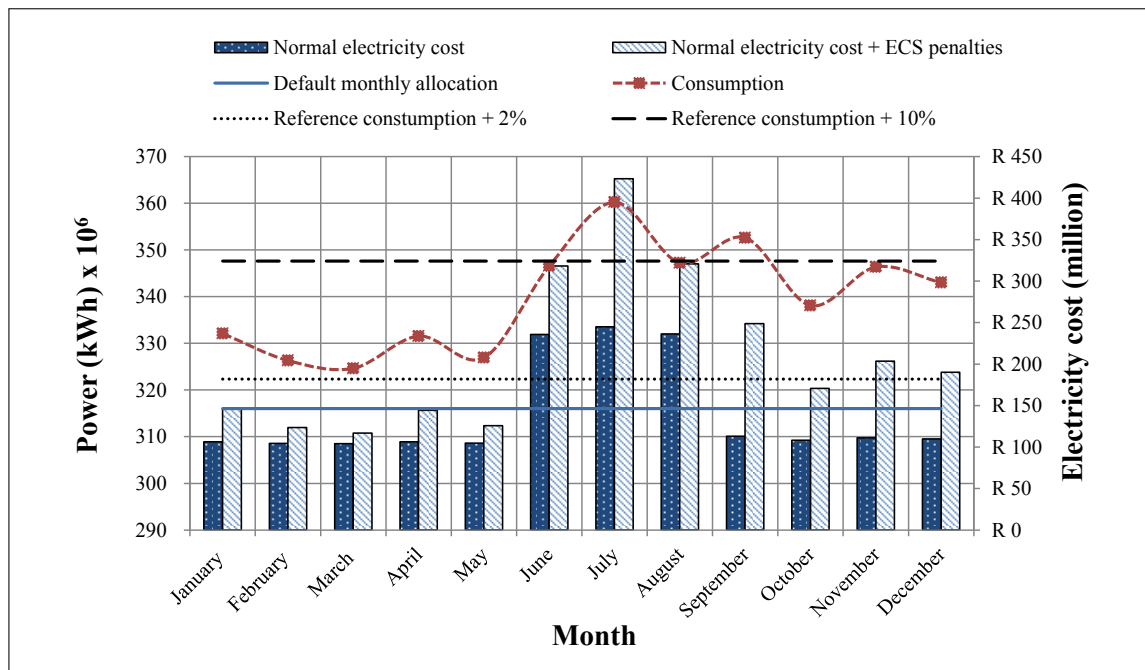


Figure 2.5: Scenario one: ECS price increase with default monthly allocation.

Scenario two is illustrated in Figure 2.6 where the same annual electricity was consumed but the ECS penalties resulted in an annual electricity cost increase of 59%. The poor allocation and high penalties from the Punitive Band resulted in the larger increase.

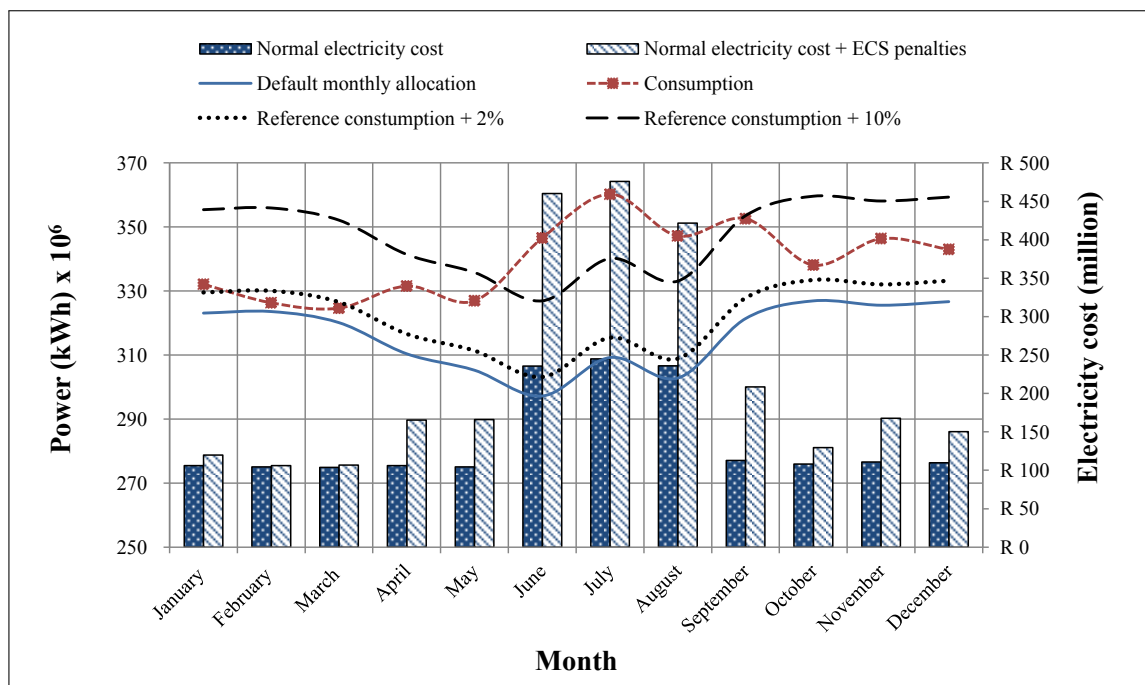


Figure 2.6: Scenario two: Poor allocation and high ECS penalty charges.

Scenario three in Figure 2.7 illustrates a scenario where the same reference consumption profile is used as the previous year (2009). It can be seen that the correct allocation of electricity according to the reference consumption has a major effect on the penalties that

would be paid, resulting in a lower price increase of 47%.

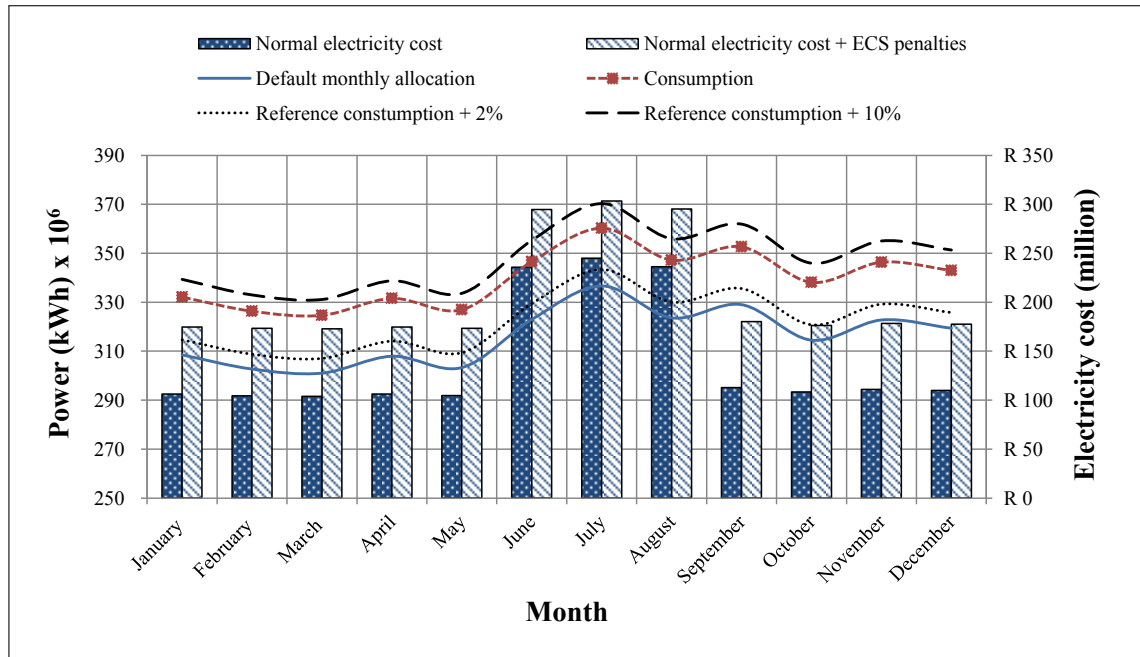


Figure 2.7: Graph illustrating the cost effect of improved electricity allocation.

Other risks associated with ECS

Implementing the proposed ECS will not be easy and requires careful balancing and consideration of some critical factors:

- It is a lengthy regulatory process, therefore initially requiring that participants participate voluntarily until rules can be established and implemented.
- Inability of customers to achieve savings overnight, thus providing economic challenges that require mitigation without placing the capture of savings at risk, such as regulatory changes in the environment that allow customers to trade and/or self-generate.
- Operational complexities due to non-standardisation and varied capacity amongst distributors will require that customers be phased into the scheme, so as to minimise the risk of inconsistent treatment of customers.

2.2.5 ECS mitigation strategies

From these predictions it should be clear that the mining group could face severe financial electricity costs when the ECS is enforced.

The following mitigations are formulated from the ECS rules and previous experiences [2]:

- A concerted effort should be made to operate below or as close to the reference consumption values as possible, as well as ensuring timely and regular communication when additional loads are anticipated.
- Planning and allocation play a critical role and can protect the customer against costly excess charges.
- Production and electricity costs for the mines in the mining group should be constantly evaluated to identify electricity savings opportunities.
- Equipment should be installed to monitor individual electricity consuming sections of the mine, monitor and identify misused electricity consumption or to quantify potential ECS penalties per load or section.
- DSM projects can be used to help fund electricity efficiency projects. The data capturing and reporting equipment required for a DSM project should be installed to provide the mine with the relevant information to evaluate electricity savings opportunities.
- Each electricity consuming section should be independent from other mining services. This will provide the client with the ability to isolate electricity consuming sections which do not influence production.
- Competent and properly trained employees should be made responsible for managing and predicting the electricity usage. A central control room for allocating electricity will be beneficial to the customer.

The state of California in the USA, has shown unambiguously that price elasticity can be beneficially exploited to entertain demand response [6]. There are also some lessons to be learned from other countries such as Brazil who implemented a similar electricity cost scheme during Brazil's supply shortage. This would give the government and customers a unique opportunity to deal with crisis situations in a more organised and less costly way [6]:

- Early warning systems should be in place, and the responsible person must communicate the severity and mitigation strategies.
- The rules and excess charges regarding the ECS should be clear and well communicated.
- An electricity rationing plan should be available and well defined with responsible personnel assigned.

Benefits of compliance

Apart from contributing to the reduction of electricity consumption and supporting the economical growth and potential of customers, the ECS would also provide the following direct benefits:

- A reduced risk of load shedding resulting from the additional spare supply capacity of the reduced demand.
- Lower electricity bill from the reduced demand.
- Reduced rate of increase in electricity prices.
- Reduced carbon footprint.
- Even lower electricity rates, both immediately and in the future.
- Income generated by trading allocated electricity, could fund additional qualifying electricity efficiency projects.

2.3 Reactive power

2.3.1 Background

The electricity costs for large consumers not only consist of kilowatt-hours consumed, but also network charges and reactive power charges that form part of the monthly costs. These could pose large financial risks to customers if not managed correctly.

A Megaflex customer's bill would consist of the items listed in Table C.1 in Appendix C. Where the Eskom Megaflex rates, illustrated in Appendix C, is a function of Time Of Use (TOU) and the demand season. Eskom power charges consists of three main charges for different power classifications, namely Reactive (kVAr), Apparent (kVA) and Real (kW) power. The relationship between these power charges is illustrated in Appendix D.

2.3.2 Power factor cost risk

For the mining industry, reactive power is of interest as large components such as induction motors used for pumping and compressed air pose high induction loads. These induction loads induce and require reactive power to operate. Not only will the reactive power penalties

affect the mine, poor power factor correction has a direct influence on the efficient operation of the machinery [7].

A high power factor (0.96) will result in lower reactive power and apparent power charges. Reactive power is presently only charged in the high demand months (June, July, August) for reactive loads with a power factor lower than 0.96. From MYPD3 Eskom proposed to include the reactive energy charge throughout the year, which motivated the study of the risks involved with reactive power charges.

The electricity charges coupled to the power factor were investigated. The goal was to derive a simplified equation to illustrate the cost risk involved. The cost risk involved with reactive power charges will be studied separately from tariff cost increases. Tariff cost increases will affect reactive power charges but the mitigation strategies differ from that of reducing Real power electricity costs. The true impact of reactive power cost increases will be illustrated proportional to the expected tariff increases. A simplified scenario was calculated to provide better insight and to help motivate mitigation strategies.

During the investigation for the study, it was found that the large loads (e.g compressor and pump motors) for the selected mining company on average had a power factor of 0.87. To illustrate the cost impact of a poor power factor, a power factor of 0.8 was defined as a poor power factor.

For the calculations the following assumptions were made:

- A constant active energy load of 10 MW was used for a 30-day calendar month.
- The mine was billed according to the 2012/2013 Megaflex rates [8].
- The charges were according to the high demand season or a winter month.
- The calculations would derive a breakdown of a load with a power factor of 0.8 and an improved power factor of 0.95.
- A 400 km electrification distribution distance was assumed.

The cost breakdown of the first cost prediction for the load utilising a power factor of 0.8 is illustrated in Figure 2.8. From the graph, the reactive power makes up 8% of the total monthly cost and transmission costs are 7%. These costs are directly related to the power factor of the customer.

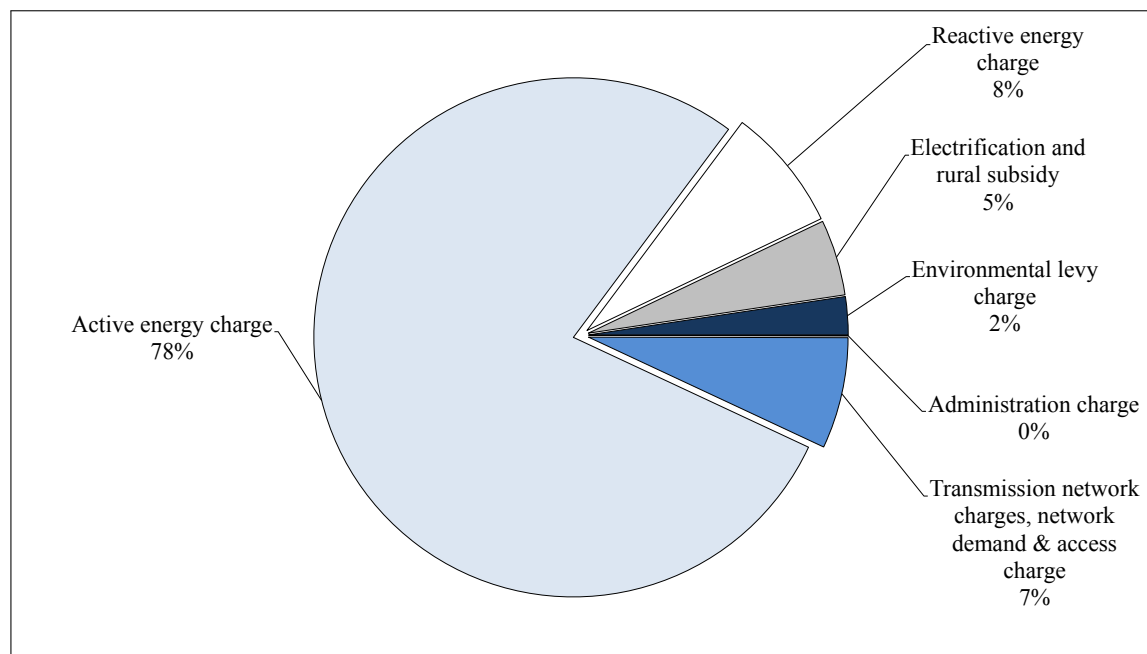


Figure 2.8: Cost breakdown of the monthly charge illustrating the effect of reactive power charges with a power factor of 0.8.

If the power factor is improved to 0.95 the reactive energy charge would only be 4% of the monthly bill and transmission, demand and network access charges 6%. This is clearly illustrated in Figure 2.9. The price comparison between the two scenarios is shown in Table 2.2.

	Power Factor = 0.80		Power Factor = 0.95		Annual price reduction for improved power factor
Annual electricity cost with reactive charges only in winter:	R	66 471 485	R	64 884 669	2%
Annual electricity cost with reactive charge throughout the year:	R	70 699 685	R	66 737 659	6%
Annual price increase with reactive power charged throughout the year :		6%		3%	-

Table 2.2: Annual price comparison between the power factor price scenarios of 0.8 and 0.95.

Table 2.2 illustrates that an improved power factor from 0.8 to 0.95 could result in annual price reduction of 2%, if reactive power charges were only implemented in the high demand seasons. The risk is also illustrated, in that a constant reactive power charge throughout the year could result in an annual price increase of 6% for a power factor of 0.8. The client could expect only half of that increase if the power factor was improved.

The next step was to derive a simplified equation to aid in the estimation of the price increase in relation to the power factor for a high demand month.

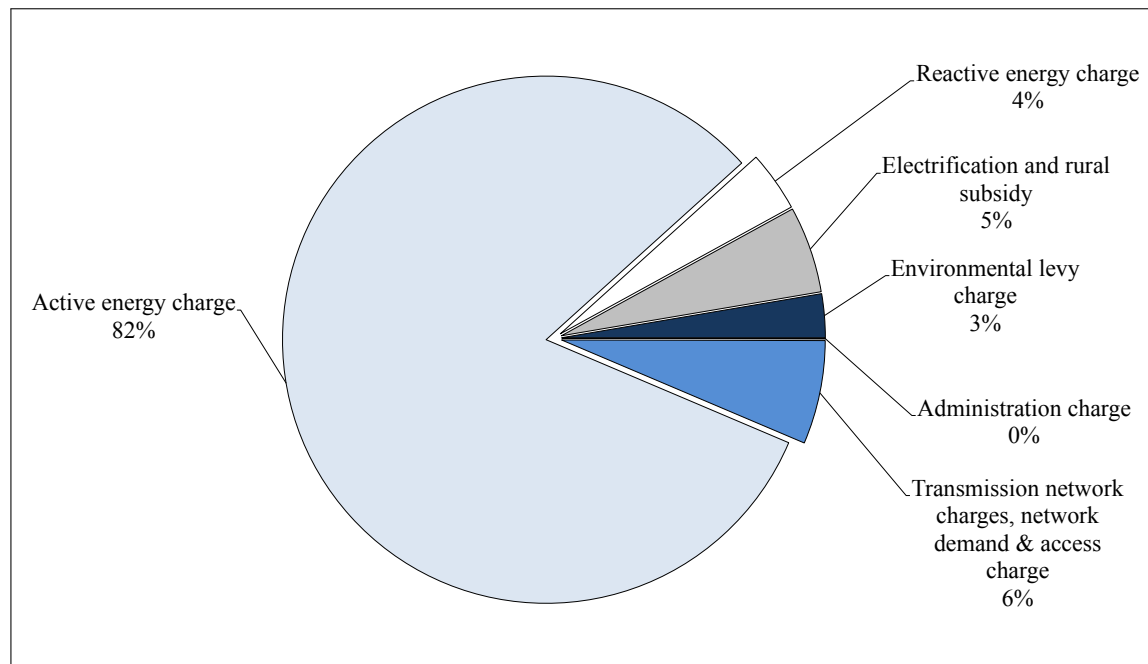


Figure 2.9: Cost breakdown of the monthly charge illustrating the effect of reactive power charges with a power factor of 0.95.

The total charges for the Megaflex client were calculated as the sum of the abovementioned charges in Table C.1 in Appendix C.

The total charge calculation for a constant load can be simplified as:

$$TC = AC + S \times (TN + NA + ND) + Q \times RE + P \times (AE + RS + EL) \quad (2.19)$$

To test the simplified approach, actual electricity charges of a mine for the selected mining company were used, where

AC = Administration charges, of R67 per day for 30 days (720 hours)

TN = Transmission network charges (R4.82/kVA/month)

NA = Network access charge (R9.93/kVA/month)

ND = Network demand charge (R18.82/kVA/month)

AE = Active energy charge (Average of R0.63/kWh)

RE = Reactive energy charge, average Megaflex (R0.09/kVArh)

RS = Electrification and rural subsidy (R0.04/kWh)

EL = Environmental levy charge (R0.04/kWh)

P = Real power (kW)

S = Apparent power (kVA)

Q = Reactive power (KVar)

Equation 2.19 can be simplified to Equation 2.20 by substituting the average Megaflex charges for a 720-hour month. The relative electricity costs for one of the mines for the selected mining company were used.

$$\text{Total electricity cost (Rand)} = 2016 + S \times (33.7) + Q \times 64.8 + P \times (496.8) \quad (2.20)$$

Equation 2.20 can be simplified to Equation 2.21 by substituting Equation D.4 and D.3 to provide an simplified cost estimation for a constant load.

$$\text{Total electricity cost (Rand)} = 2016 + P \left(\frac{1}{\cos \theta} \times (33.7) + \tan \theta \times 64.8 + 496.8 \right) \quad (2.21)$$

Using Equation 2.21 and an array of power factors, Figure 2.10 was developed as an aid for customers. This will help in identifying possible cost risks if Eskom charges reactive power rates not only in winter months but throughout the year. The ideal goal is for the customer to achieve a power factor of above 0.96 throughout the year.

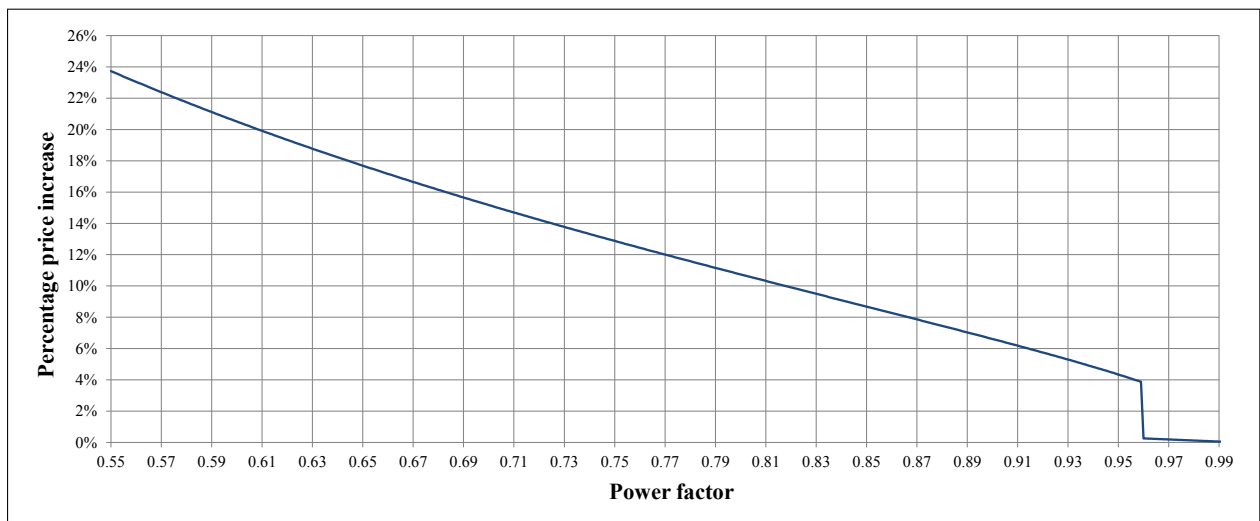


Figure 2.10: Illustration of the monthly price decrease in relation to the power factor.

From these discussions, the evident financial advantages of installing power factor correcting devices were illustrated. Apart from these financial benefits, the improved power factor

will also provide better efficiency of large machines, resulting in less required maintenance, possibly leading to an increase in production.

2.3.3 Power factor mitigation strategies

There are several ways to improve the power factor of equipment and industrial plants, and these power factor mitigation strategies could have large financial implications. The most common and efficient way for a mine would be to install power factor correcting capacitor banks to get the power factor above 0.96 during peak demand periods, and thus avoid extra costs. However, a capacitor bank installation to achieve a unity (1) power factor requires highly complex designs and exorbitant costs [9]. Also to consider is that the annual expenses for maintenance of these capacitor banks are expected to only amount to 2% of the purchase price [10]. Capacitors have no moving parts. The relays and breakers are the only parts that require maintenance in the high voltage banks.

A payback period of less than five years can be expected for a R15-million capacitor bank [9]. This prediction was calculated with reactive power costs only in the high demand season. The same calculation was repeated but with reactive power costs throughout the year. The payback graph is illustrated in Figure 2.11, and shows that the payback period then reduces to less than three years.

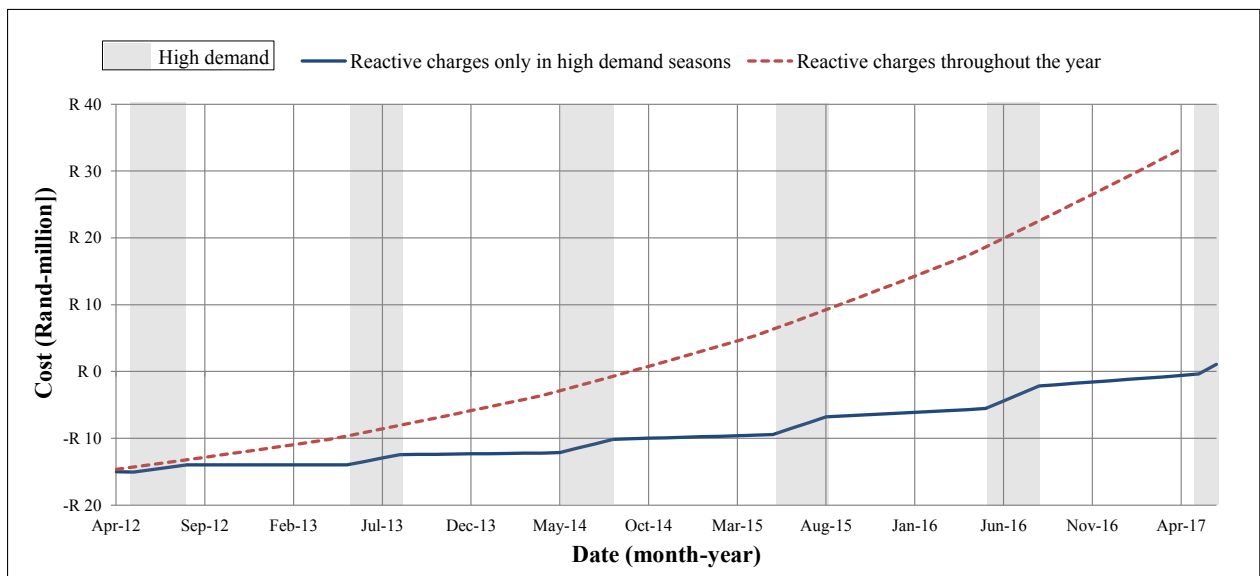


Figure 2.11: Comparison between payback periods when reactive power is charged throughout the year.

Figure 2.11 clearly illustrates the need for power factor improvement and the reduced payback period for the scenario where reactive charges will be applicable throughout the year. Reactive power charges pose a large financial risk to customers or mines not managing their

power factor correctly. Well developed mitigation strategies are available with motivated payback periods.

2.4 Carbon tax

2.4.1 Background

There are several human-induced heat trapping gases emitted globally that pose a threat to the environment [11], [12], [13]. A report published by the Intergovernmental Panel on Climate Change (IPCC) announced that the largest part of global warming observed over the last 50 years was contributed by human activity [14]. It has been formally reported that the human-induced greenhouse gases (GHG) are the primary cause of global warming [15]. The effect of GHG is like a blanket around the globe, preventing the natural irradiation of infrared energy from earth's atmosphere. Trapping this energy source has an induced effect of a predicted global mean surface temperature rise of between 1.4°C to 5.8°C over the next 100 years [16].

Processes that destroy or remove GHG are known as sinks where sources are processes that generate GHG. Sources such as volcanos or natural burning fires have been present for many years; it is since the mass human interference of the sources and natural sinks that the GHG is inducing climate changes [17]. The CO₂ equivalent is an internationally accepted measure that expresses the amount of global warming of GHGs in terms of the amount of that which would have the same global warming potential [18]. The six most important greenhouse gases with their global warming potential are shown in Table 2.3.

Gas	Source	Global Warming Potential (GWP)
Carbon dioxide (CO₂)	Biomass respiration and burning, land-use change, energy, transport, industry, etc.	1
Methane (CH₄)	Energy, landfills, ruminants, waste treatment, rice agriculture, biomass burning, etc.	21
Nitrous oxide (N₂O)	Transport, industry, livestock and feed, biomass burning, etc.	310
Hydrofluorocarbons (HFCs)	Refrigeration and air-conditioning industries, fire fighting agents.	140 - 11700
Perfluorocarbons (PFCs)	Electronics industry processes.	6500 - 9200
Sulphur hexafluoride (F₆S)	Dielectric gas for high voltage applications.	23900

Table 2.3: Table illustrating the global warming potential of greenhouse gases [19].

From 1991 negotiations have been formulated to establish an international treaty for global climate protection. This resulted in the United Nation Framework Convention of Climate

Change (UNFCCC) in May 1992. The Kyoto Protocol was established during a conference of three parties in Kyoto with a binding set of obligations (Annex I) for countries to reduce their greenhouse gas emissions by on average 5.2% below their 1990 levels. This was to be implemented in the period 2008-2012 [20]. The countries who agreed were 38 industrialised countries and 11 non-industrialised countries in Central and Eastern Europe.

South Africa forms part of a developing countries group and is not obligated to reduce emissions, according to the Kyoto Protocol, but several announcements have been made that South Africa is none-the-less committed to reducing their carbon emissions [21]. One such effort to mitigate the climate effect of GHG is a carbon tax proposed by the South African government. The proposed carbon tax will act as an incentive to induce behavioural changes and to encourage energy efficiency measures.

2.4.2 Carbon tax cost risk

An exact value has not been allocated to carbon tax as yet. The carbon tax summary from the annual government budget speech is as follows [22]:

- The estimated start date for carbon tax is 1 January 2015.
- The proposed tax rate would be R120 per tonne of CO₂ equivalent.
- The carbon tax rate could increase by 10% annually from 2015 until 2020.
- Only the last 40% of the total CO₂ emissions will be taxed.
- An offset percentage of 5-10% could be introduced to allow investment in other projects.
- Gradual phasing out of the environmental levy could be implemented once carbon tax is established.
- Some of the revenues generated through carbon tax could fund energy efficiency incentives.

The carbon tax White Paper policy was released in May 2013 for public comments. The released White Paper corresponds to the statements made in the budget speech. Added points from the White Paper include that an extra trade allowance is added for certain sectors, additional to the offset percentage. For the mining industry, a initial offset of 60% with a trade allowance of 10% and a maximum offset of 10% is allowed. The carbon tax will only cover Scope 1 emissions in the tax base. Scope 1 emissions include carbon dioxide, methane, nitrous oxide, perfluorocarbons, hydrofluorocarbons and sulphur hexafluoride [23]. According to the 2011 White Paper, the Department of Environmental Affairs (DEA) will

require mandatory reporting for entities that emit more than 100 kilo-tonnes of GHG or consume the equivalent amount of electricity. Scope 2 emissions are indirect emissions which result from the electricity purchased.

Scope 2 emissions are indirect emissions which result from the electricity purchased (emissions from Eskom's power stations), and it is these emissions that the mining environment will mostly produce. Other complementary measures, such as the energy efficiency savings tax, will be introduced to encourage businesses to reduce their Scope 2 emissions. As the carbon tax from Scope 1 emissions will be directly passed onto the mining sector from Eskom, these additional costs motivated the development of a simplified equation illustrating the estimated price increase that could be expected from the proposed carbon tax in relation to Scope 2 emissions.

The relationship between Scope 2 CO₂ emissions and electricity consumed can be provided by the emissions factor relationship illustrated in Table 2.4. From the presented Eskom measurement and verification reports the carbon dioxide generation for coal fired power plant is 0.973 t/MWh [24].

	Factor 1 (Total energy sold)	Factor 2 (Total energy generated)	1 kWh	1 MWh
Coal use	0.56	0.54	kilogram	tonne
Water use	1.42	1.37	litre	kilolitre
Ash produced	161.00	155.00	gram	kilogram
Particulate emissions	0.32	0.31	gram	kilogram
CO ₂ emissions	1.03	0.99	kilogram	tonne
SO _x emissions	8.23	7.93	gram	kilogram
NO _x emissions	4.35	4.19	gram	kilogram

Table 2.4: Power consumption and emission relationship [25].

For this study and from Table 2.4 the relationship between electricity consumption can be calculated using Equation 2.22. Where C is the active electricity consumed.

$$CO_2(\text{tonnes}) = 1.03 \times C(\text{MWh}) \quad (2.22)$$

From the abovementioned budget speech summary, the estimated cost per tonne CO₂ emitted is R120 providing Equation 2.23.

$$\text{Carbontax}(\text{Rand}) = 1.03 \times C(\text{MWh}) \times 120 \quad (2.23)$$

From the updated carbon tax policy paper, it is assumed that only the last 40% of the emitted CO₂ will be taxed in the electricity generation industry. Equation 2.24 is derived to provide the estimated cost involved with the predicted carbon tax rates. Reductions in the

tax threshold could be implemented after the threshold levels have been finalised. Trade and process emissions could also aid in the reduction of the percentage to be taxed, with different tax percentages for different industries [26], [22].

$$\text{Carbon_tax}(Rand) = \frac{1.03 \times (P \times 0.4) \times 120 \times 720}{1000} = 35.6 \times P \quad (2.24)$$

Where P is the active power in kW and assuming a 720 hour month. Equation 2.24 can be included in the total cost estimation (Equation 2.21) for a constant load resulting in Equation 2.25.

$$TC = 2016 + P \left(\frac{1}{\cos \theta} \times (33.7) + \tan \theta \times 64.8 + 496.8 + 35.6 \right) \quad (2.25)$$

From Equation 2.25 the customer could expect a price increase of least 6% assuming that carbon tax is only paid for the last 40% of the active electricity used, or an additional 5 c/kWh. For the calculated increase, it assumed that the electricity levy is still included in the billing.

Carbon tax has not been formally approved yet, but the kick-off date is estimated to be early 2015 and increase annually by 10%. Figure 2.12 illustrates the predicted carbon cost per kWh for the 10% predicted price increase.

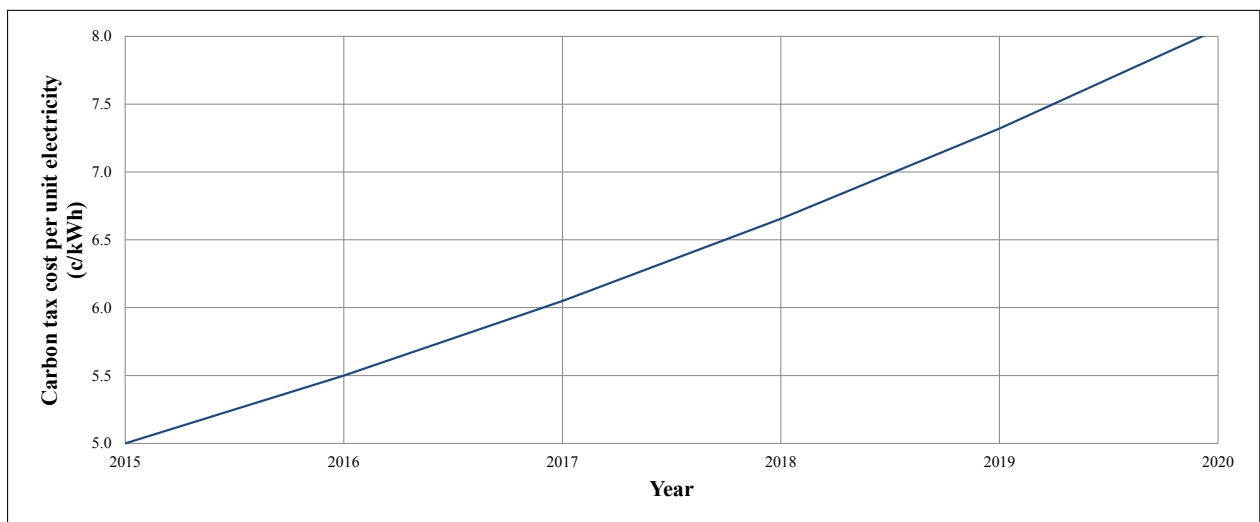


Figure 2.12: The predicted carbon tax cost increase for 2015-2020.

2.4.3 Carbon tax mitigation strategies

Carbon tax is a reality and the estimated date for implementation is 2015. The problem faced by the mining environment is to find the balance between reducing their carbon footprint

whilst investing in projects that will increase production.

Funding models are available for the reduction of carbon emissions; one such model is the Clean Development Mechanism (CDM). CDM is an arrangement defined under Article 12 of the Kyoto Protocol [20], which allows developing countries to receive funding for carbon-reducing projects. The funds are invested by industrialised countries, which in return will receive Certified Emissions Reductions (CERs) according to the CDM rules. The received CERs can then be traded or used to obtain the reduction targets under the Kyoto Protocol.

There are several controversial concerns regarding the Kyoto Protocol including the non-commitment of countries like the USA, Canada and Japan who are not willing to participate. The list of countries that are willing to implement the protocol is listed in Annex I [27], [28].

The uptake of CDM projects has been slow, due to following rumoured hurdles [29]:

- DSM projects have a negative impact on the potential of implementing CDM projects.
- CDM finance is difficult to acquire.
- New baseline and monitoring methodologies must first be developed and approved for CDM application.
- CERs have reduced in value from €20 per tonne in October 2008 to less than €1 per tonne at the end of 2012.

The rules regarding the CDM could be seen as complex and sometimes unclear in terms of additional projects [30]. A CDM project is considered *additional* if the carbon emissions reductions are obtained above the emissions reductions from business as usual. Resources are available to simplify and the classify projects as *additional* or not [31]. Energy efficient projects developed to reduce electricity consumption and electricity costs can also be used to generate CERs [32], [29].

The estimated spot price for CERs, at the start of 2011, was almost R120 per tonne CO₂ which made the viability of submitting a energy efficient project as a CDM project very attractive. A simplified scenario was presented where a mine would implement a 1 MW electricity efficient DSM project. Assumptions were that the project would cost R6-million and the project would be paid back within an estimated 17 months, and electricity rates were according to the 2012 Megflex rates. If the mine submitted the project as a CDM project, the mine would repay the project in a shorter period [32].

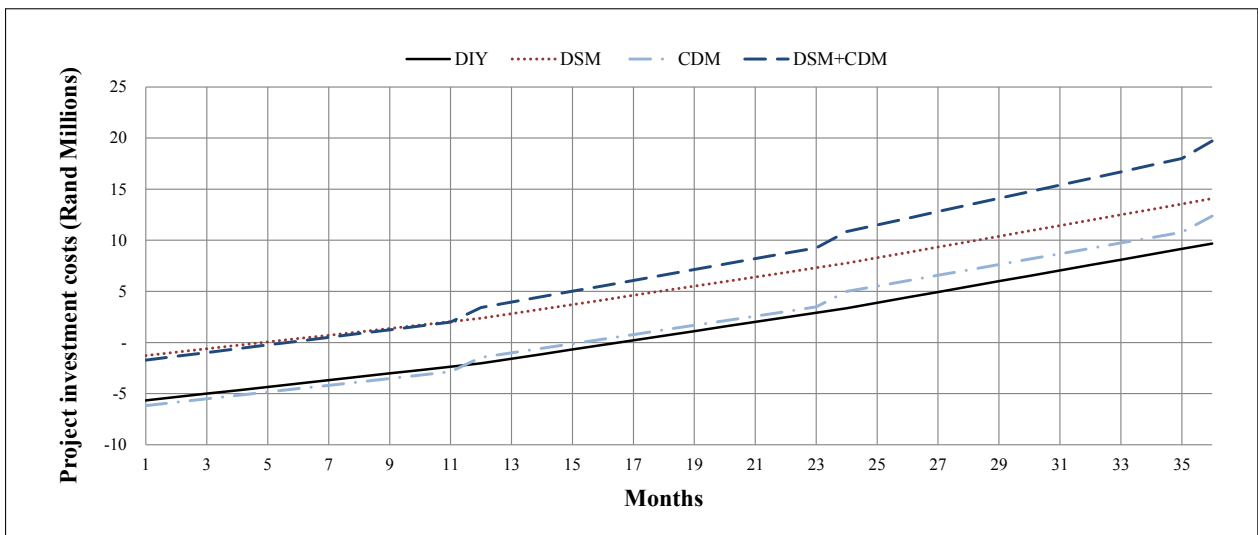


Figure 2.13: Payback calculations for a normal and CDM submitted 1 MW electricity savings project [32].

The scenario of implementing a CDM project is illustrated in Figure 2.13, showing the CERs price relations and the payback for a energy efficient project, based on the assumption of an CER spot price of R120. The CDM could be considered as an additional mitigation strategy to help off set the cost burden of carbon tax.

Unfortunately the present price of the CERs is much lower, R3.50 was recorded at the end of 2012 with the historical trend illustrated in Figure 2.14. The price is very volatile and unpredictable - this uncertainty could lead to people not partaking in the process or registering their projects. The cost involved in registering and partaking in CDM is not viable with such a low CER price. The estimated cost of registering a CDM is R500 000 and the registration would only be paid back within 17 years for the same 1 MW reduction scenario, using a spot price of R3.50 [32].

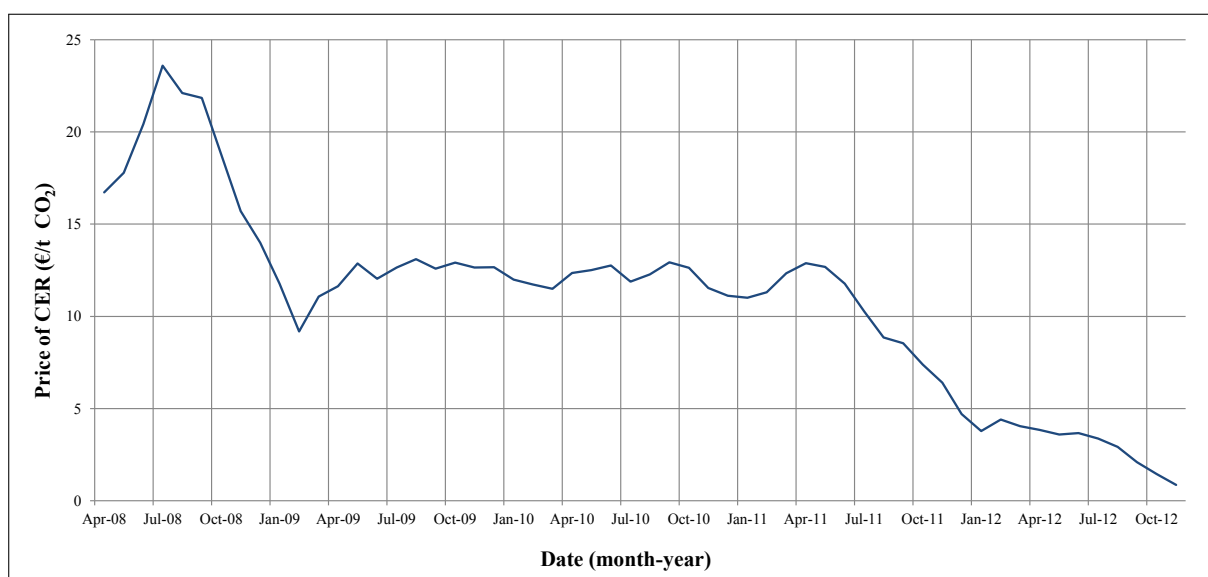


Figure 2.14: History trend of CER spot price¹.

From the 2013 budget carbon tax is a reality. South African Income Tax Act of 1962 government released a tax incentive numbered Section 12I, which was available from 2009. Section 12I incentives incorporate electricity efficiency specifically for manufacturing related projects. These projects have a 10% demand reduction target [33].

The downside of the Section 12I incentive is that projects which have already received funds from other incentives will be excluded and savings obtained from these projects will not be claimable for other incentives or schemes. A second proposed incentive namely Section 12L is in the reviewing process and focuses primarily on energy efficient projects. There are several requirements for Section 12L that could aid in the process once it has formally been rolled out [33]:

- Formally appoint a Measurement and Verification (M&V) professional who is part of a South African National Accreditation System (SANAS) Measurement and Verification body (M&V).
- Register with the South African National Energy Development Institute (SANEDI) for the energy efficiency tax allowance.
- Task the M&V professional to compile an M&V plan and the needed baseline report according to the prescribed standards.
- Submit the reports to SANEDI for the tax year applicable.
- If the application is successful SANEDI will issue a formal energy savings certificate.
- The energy savings certificate could then be submitted to the South African Revenue Service (SARS) with the related tax claim.

The Section 12L incentive includes all energy efficient projects that result in a reduction of energy in all forms and is not limited to electricity. From the presented rules regarding Section 12L, incentives can be received from an energy efficiency project which has already received forms of other funding. There are opinions that indicate that the same rules from Section 12I could be applied to Section 12L with regards to additional funds [34]. The Section 12L incentive can be calculated using Equation 2.26 [35]:

$$\text{Allowance(Rands)} = \frac{A(\text{kWh}) \times B(\text{R/kWh})}{2} \quad (2.26)$$

Where A is the energy savings realised from the project and B is the lowest feed tariff. After this, the allowance must be taxed resulting in only 28% of the allowance to be returned to the company. Assuming the lowest line feed of 0.55 R/kWh [36], a 1 MW energy efficient

¹<http://www.eex.com/en/Market>

project could result in an additional R644 000 annual electricity cost savings resulting from the Section 12L tax incentive.

An advantage of this is that the requirements for a DSM project overlaps with the requirements of an Energy Efficiency DSM (EEDSM) project. This provides an opportunity for obtaining financial benefits for a DSM project and savings realised from tax incentives. It is also recommended that the project must first register as an EEDSM project and use the requirements of EEDSM to apply for tax incentives [37]. A simplified investment guideline would be Section 12L which provides 0.26 R/kWh tax deduction where Eskom's DSM programme will provide an approximate 0.42 R/kWh cash injection. It is therefore recommended that projects pertaining only to electricity should consider Eskom's DSM funding [38].

2.5 Predicted price hikes in the gold mining industry

2.5.1 Background

South Africa has been facing dramatically increased electricity tariffs since 2008. The historical price increases are illustrated in Figure 2.15, comparing consumer price inflation with yearly average electricity price adjustments. These price increases pose a great risk to the gold mining industry which are heavily dependent on electricity and one of the largest consumers of electricity in South Africa. Eskom applied for annual price increases of 15% for 2013 to 2017, but only a 8% increase was approved by NERSA [39], [40].

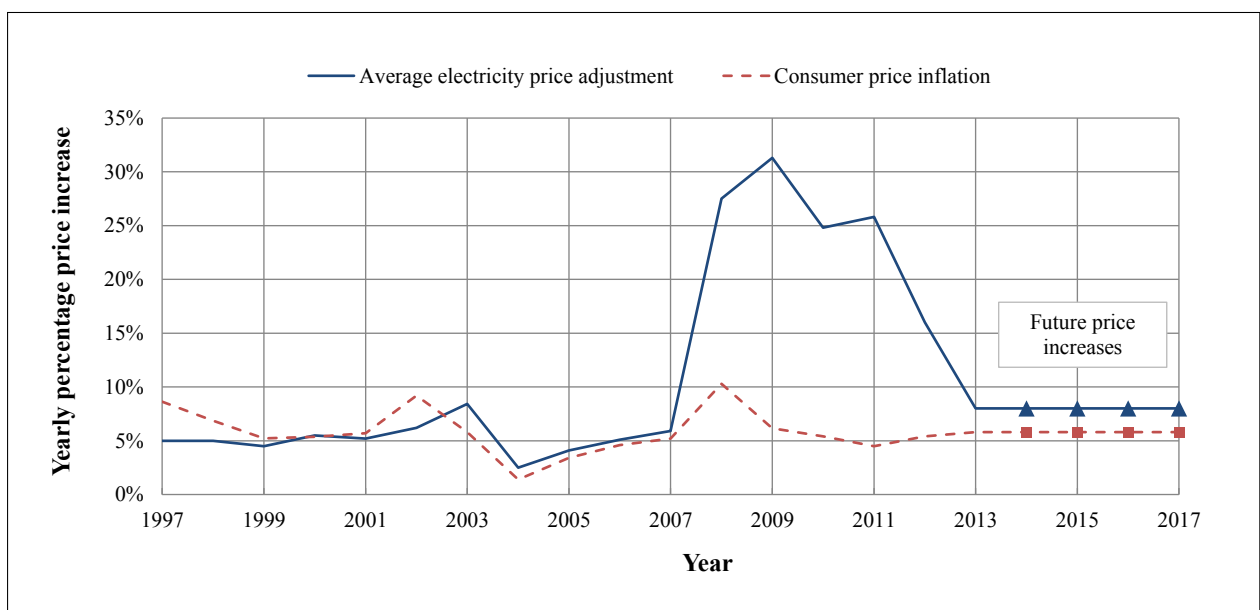


Figure 2.15: History of average annual price increases from Eskom.

2.5.2 Price increase cost risk

Generically speaking, the electricity costs for the mining and quarrying industries amount to 5% of the total input costs [41]. From empirical studies it is suggested that the mining and manufacturing sectors are likely to suffer the largest declines in output and the resultant reduction in the work force from reducing employment costs, related to the rise of electricity costs [42]. It is also very difficult to pass on the costs to consumers due to a volatile gold price and South Africa's failing production rates when compared internationally [43].

The annual electricity cost from 2005 and the predicted cost for the selected South African gold mining company is illustrated in Figure 2.16. The consumption projection illustrated is based on the average historical reduction of 3%. In comparison, the electricity consumption and cost, from 2010 to 2013 of another gold mining company, is illustrated in Figure 2.17. A 40 MW reduction was achieved but the above-inflation price increases resulted in an annual cost increase of R 1.05-billion. For the Sibanye mining company, direct mining cost increases were above inflation. From the reports, this was accredited to the higher wage demands and electricity costs almost doubling every five years [44].

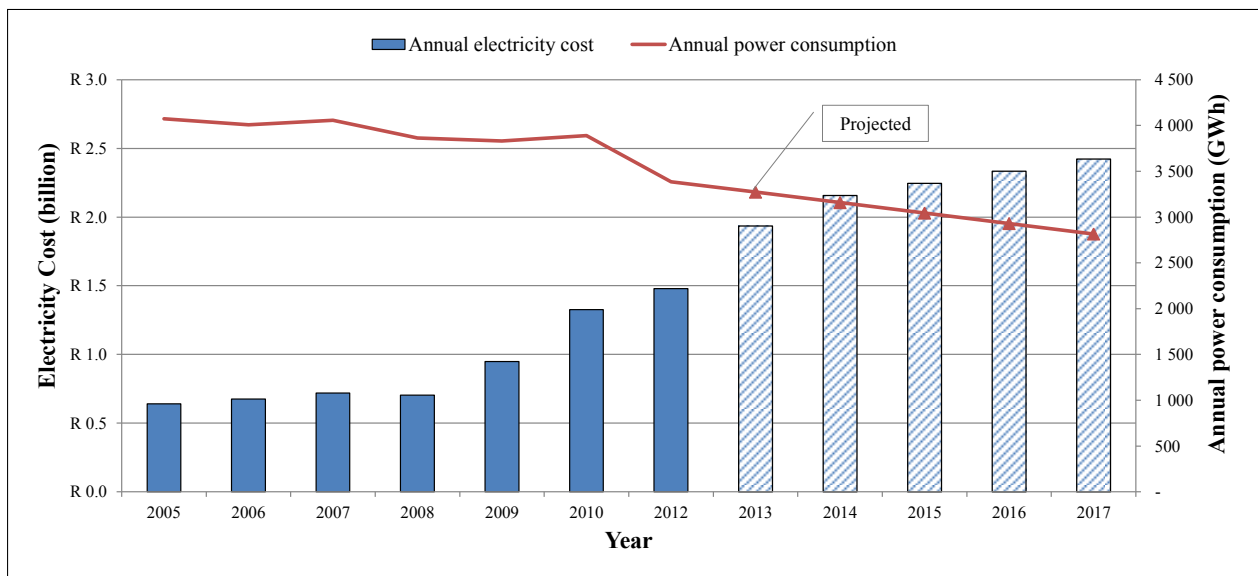


Figure 2.16: Power costs increases for a selected mining company 2005-2017.

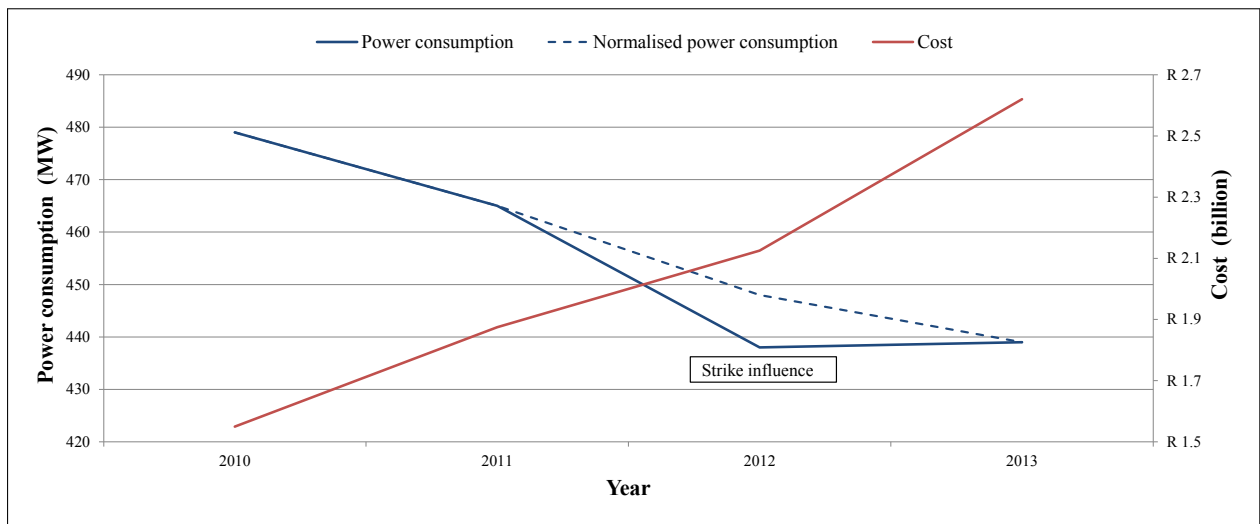


Figure 2.17: Power consumption and electricity price comparison [44].

The alarming price increases motivates the study to model the true cost of electricity for the gold mining company analysed. For the selected gold mining company, the direct mining cost is divided into the different operational cost such as labour, water, capital and electricity. The direct operating cost for the selected mining group was analysed and the direct mining cost for 2006 and 2012 were compared, as shown in Figure 2.18.

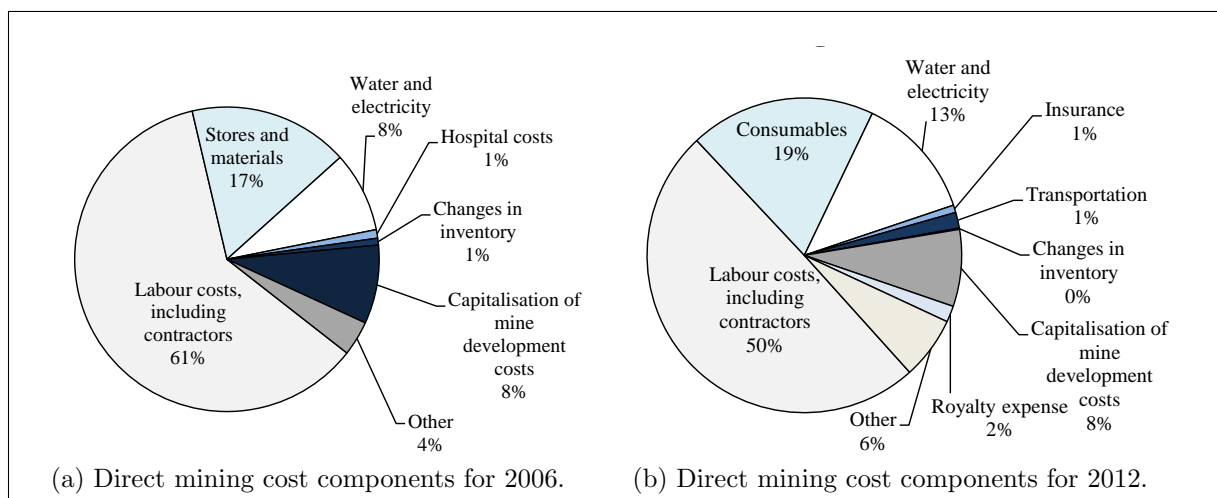


Figure 2.18: Direct mining cost comparison between 2006 and 2012.

The direct mining cost increase can be noted in the water and electricity components of the operational costs, increasing from 8% to 13%. It is concerning to know that the total operational cost has increased by 45% from 2006 to 2012. From the presented data and predicted electricity price increase of 8%, the electricity cost for the selected mining company could reach up to 15% of the cash operating costs in 2017.

2.5.3 Price increase mitigation strategies

Eskom provides several energy financing models that could assist customers in reducing electricity costs. This section will focus on the funding models available.

DSM funding presently remains a working and viable electricity cost reduction programme and several South African industries have utilised it [45]. Funding of these DSM projects is sometimes crucial for the return of investment policy of some companies [46]. Some of the funding models that could be used for projects on the major energy-consuming services of a gold mine are illustrated in Table 2.5 [47].

The applicable funding mechanism is briefly discussed below and is summarised in Table 2.5 including the requirements and rules regarding the funding, minimum target obligations and required savings. For this study, Residential Mass roll-out was not considered as it was not applicable to this study.

	ESCO Process	Standard Product	Standard Offer	Performance Contracting
Size	> 1MW	< 5MW	< 5MW	> 5MW or 30GWh in three Years
Approval process	6-18 Months	< 2 Weeks	< 2 Months	3-4 Months
Savings	Peak Clip, EE 24h, Load Shift	kWh 24/7	EE Savings 6am - 10pm	Different rates for 6am-10pm and 10pm-6am
Value	Max: R5.2-mil/MW	85% of rebate (R5.2-mil/MW)	Max: R5.2-mil/MW	Bid rate in tender up to 55 c/kWh
Payment	During implementation	100% after installation	70%: After implementation, 10% after Year 1,2&3	R/kWh payment (delivery based)
Duration	5 Years	Client pledge to save for 3 Years	3 Years	3 Years
Pros for ESCOs	After implementation no risk	Requires no formal contract	Paid based on performance after project	Caters for bulk projects
Cons for ESCOs	Not reimbursed for over-performance	Technology needs to be registered at Eskom (time consuming)	Maintain system for 3 Years	Only gets savings on verified MWh savings
Technology	Custom or Hybrid solution	Limited to specific products on a published list	Limited to categories of technology on a published list	Custom or hybrid solution
Philosophy	Pay ESCo predetermine fixed cost after successful implementation.	Replace less energy efficient technologies. Programmable or control system. Predictable saving must be attached to technology.	Eskom pays predetermined R/kWh for savings achieved upon MAD verification.	Project developer bids bulk savings. Payment delivery based.

Table 2.5: Comparison between the different funding models provided by Eskom.

ESCO Process

ESCOs may interact, serving both the client and Eskom, providing help regarding research project management which could be of great help to the client [48]. For this model, the ESCo would request funding for the client according to a prescribed rate which then could be used to fund the project. The available and benchmarked technologies are listed in 2.6. One advantage of the ESCo model is that load shift and peak clip projects are funded which could financially aid the client in implementing monitoring infrastructure and annual electricity cost savings. The client would then commit to the proven savings for five years.

Programmes technologies	Maximum benchmark (Rand-million/MW)
Lighting & HVAC	5.2
Hot water	6.3
Demand response	3.9
Compressed air	4.4
Process optimisation	5.2
Other	5.2

Table 2.6: Rates and applicable technologies for the ESCo funding model [47].

Aggregated Standard Product

The Standard Product offers customers an opportunity to replace inefficient technologies with a list of efficient equivalent technologies. The preapproved rebates and savings are calculated and published by Eskom. Only technologies approved by Eskom will be considered for the Standard Product programme. The goal would be to provide savings for projects of between one and five Megawatts, with the customers receiving full rebates once the programme is installed and the customer pledges to maintain the savings for three years.

If interested, the customer must complete a project application. For this study it is assumed that the customer has implemented the known products, has been contacted by Eskom, and the cost comparison between other funding methods is not performed.

Standard Offer Programme

The alternative funding model would be the Standard Offer Programme where the savings obtained from the project would be sold back to the service provider (Eskom) at a predetermined rate. The organiser of the project would be paid after the project has completed 70% of the total project investment cost. The remaining 30% would be paid back evenly over the next three years to ensure sustainability [47]. The available standard offer rates are listed in Table 2.7. The Standard Offer programme offers incentives for electricity savings projects of 50 kW to 5 MW for savings between 06:00 and 22:00.

Target technologies	Maximum benchmark (Rand-million/MW)	c/kWh
Energy efficient lighting systems	5.25	42
LED lighting technologies	6.86	55
Building management systems	5.25	42
Hot water systems	5.25	42

Table 2.7: Rates and applicable technologies for the Standard Offer funding model [47].

Performance Contracting

This last funding method is similar to the ESCo model, and aims at reducing weekday electricity consumption between 06:00 and 22:00. All the infrastructure costs will be paid by the customer or ESCo and after the savings have been verified, the client/ESCo will be remunerated. The amount paid to the developer is through negotiations or a bidding process. The aim would be to significantly reduce contractual complexity, improve sustainability and reduce project lead times. The maximum rates related to the applicable times for performance contracting are listed in Table 2.8. This funding method has a required minimum three-year 30 GWh target.

Period	Base Rate (c/kWh)	Reduced Rate (c/kWh)
High rate (06:00-22:00)	55	42
Low rate (00:00-06:00 ; 22:00-00:00)	10	0

Table 2.8: Rates applicable for the Performance Contracting funding model [47].

Comparison between funding mechanisms

Each funding mechanism must first be reviewed and accepted for an appropriate technology applicable to the client. For the gold mining industry, the three mechanisms reviewed were the ESCo Process, Standard Offer and Performance Contracting.

For the comparison, an implemented compressed air project at Modikwa Platinum Mine was used as a case study. The compressed air supply and layout for a gold mine is very similar to that of a platinum mine. The baseline and the savings profile was presented. A peak clip project was first implemented whereafter a energy efficient project was implemented. Valves were installed for the project at high consuming sections, in conjunction with automated compressor control implemented to control the supply pressure automatically according to a specified profile. The electricity savings results are shown in Figure 2.19.

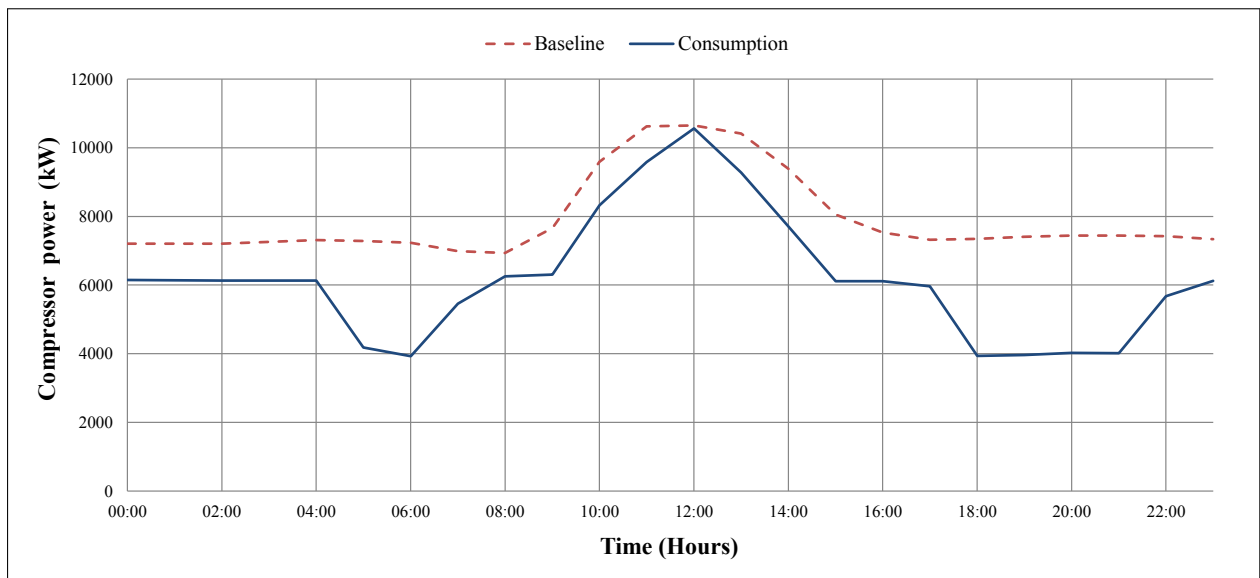


Figure 2.19: Compressor electricity profile of Modikwa Platinum Mine.

The following assumptions were made for the DSM funding mechanisms:

- The project costs for the peak clip project (3.4 MW) were the maximum benchmarked value of R7-million.
- The project costs for the energy efficient project (1.6 MW) was the maximum benchmarked value of R11.6-million.
- The client (mine) would receive 100% funding for both projects on the ESCo model, but would have to apply for a loan at an interest rate of 13% if the project would be installed and managed by the mine.
- The electricity cost savings of the project would be invested, yielding a return of 5%.
- Calculations were according to 2012/2013 Megaflex rates with an estimated price increase of 8% annually.
- Electricity savings were obtained throughout the year.

The payback periods for the cosponsoring technologies incorporating the predicted price increases from 2012 to 2017 are illustrated in Figure 2.20.

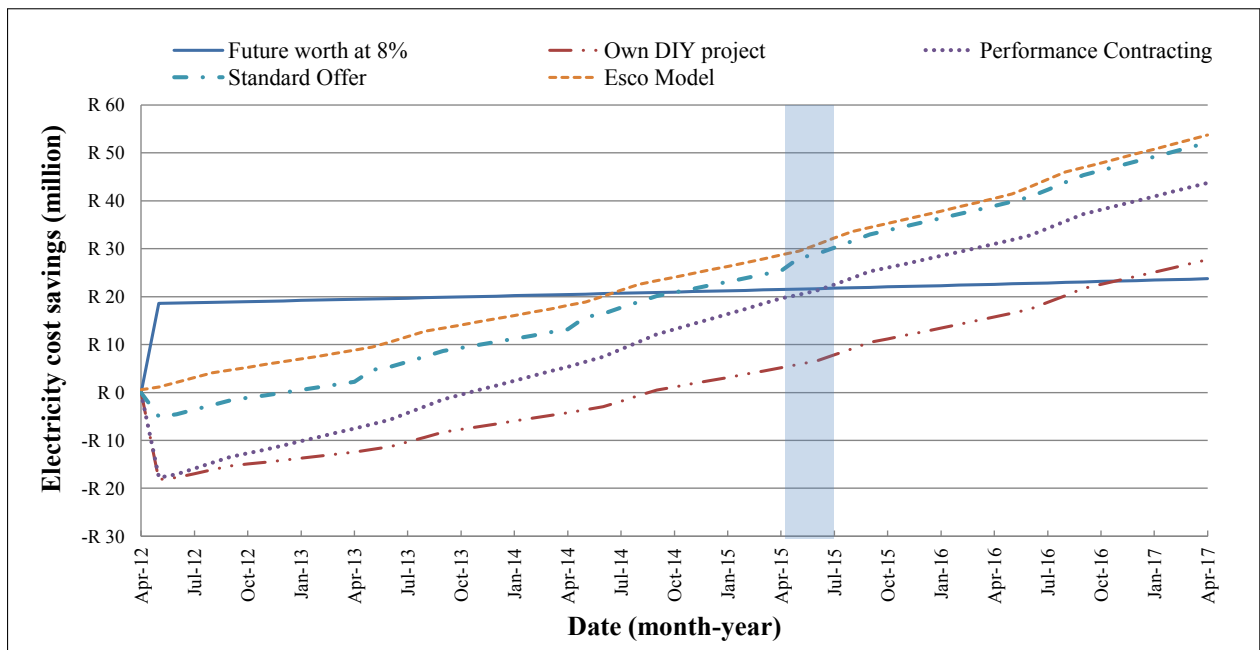


Figure 2.20: The estimated payback periods and cost for the DSM models provided by Eskom.

The uncertainty of DSM funding remains a risk but the payback periods and the much higher electricity cost makes the DSM investment more attractive. As there are practical challenges linked to DSM funding that also remain a risk and due to the cost occurred in the process, it is recommended that the fastest and least-costly measures be implemented first [49].

2.6 Design of a model

From the previous sections of identified cost risks, it was shown that the identified mining company could pay above-inflation rates or abnormal electricity charges, according to their electricity consumed. There are two type of electricity risks identified, namely time-critical cost risks and service or production cost risks.

Service or production cost risks include predicted price increases and carbon tax. These risks are confirmed for the future and to mitigate these cost risks, electricity must be reduced and additional cost incentives can be obtained.

Time-critical cost risks are high electrical costs related to a specific period usage, such as high demand seasons or peak period usage. The ECS is also seen as a time-critical cost risk due to the related period of electricity shortage and the management of the electricity usage according to the defined baseline levels. Time-critical cost risks pose the the greatest cost risk in regards to price increase as shown in this chapter. It is thus proven in this chapter that the combined effect of these cost risks can have a detrimental effect on the operational

cost of the selected South African gold mining company.

As a first step in designing a model to predict cost risks, the identified cost risks were listed and quantified into the minimum and maximum potential price increase, as well as the minimum and maximum price reduction. From these predictions certain scenarios can be derived to provide the mining company with the potential combined effect of the risks. The scenarios can be used to plan or derive action plans to mitigate the risk. The impact of each risk can be determined, providing the mining company with the ability to invest in mitigation strategies for the risk with the highest cost potential. The approach taken to derive these risk scenarios is illustrated in Figure 2.21.

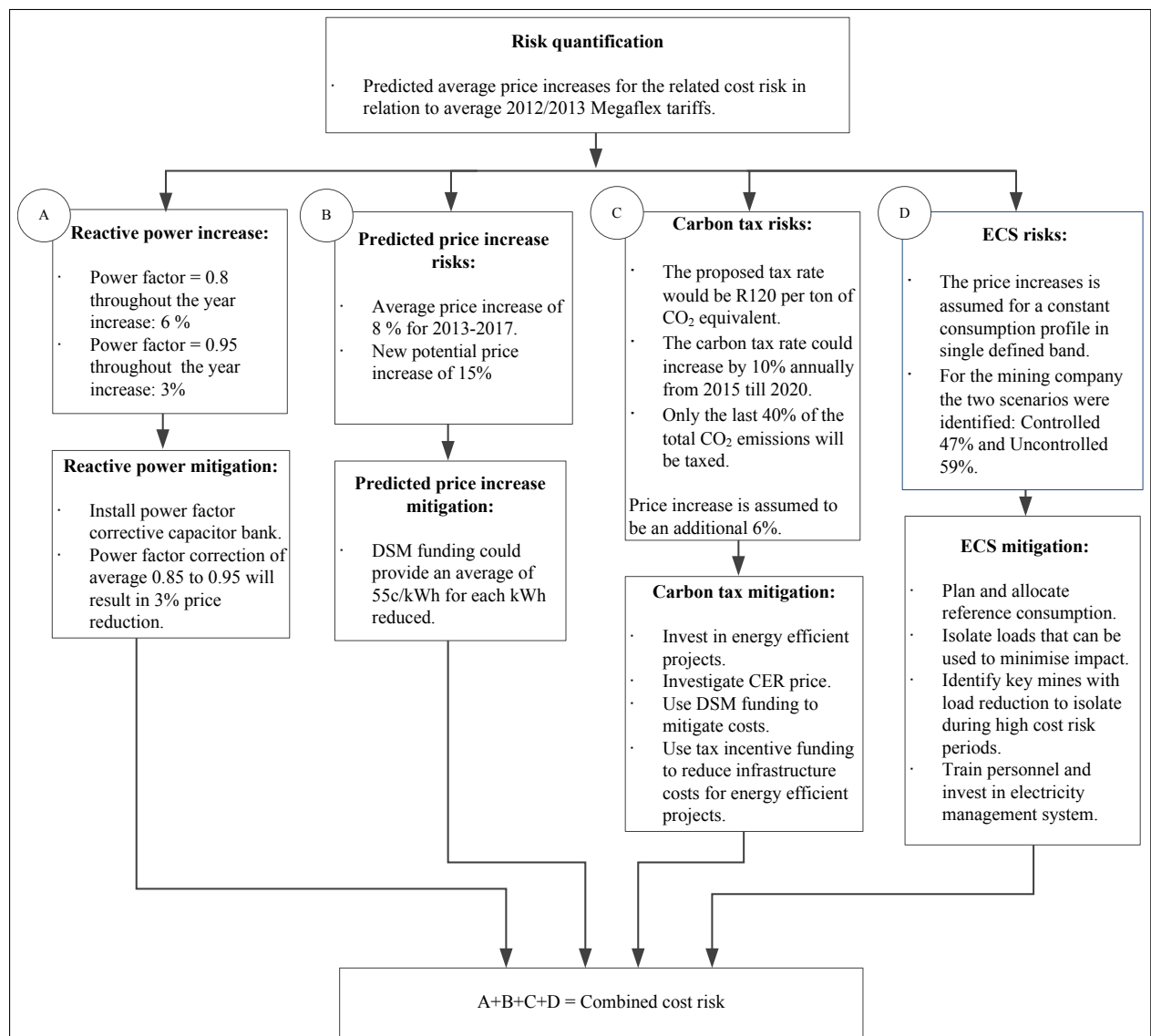


Figure 2.21: Approach for quantifying the combined cost risk.

From the qualification model, it stand to reason that all the available incentives for reducing electricity consumption must first be utilised. The available and proven methods to reduce electricity on the main consumption services on a gold mine will be discussed in Chapter 3. Different scenarios were derived for the applicable price increases related to the cost risks

are illustrated in Table 2.9 and discussed below. The scenarios are based on assumptions of potential combinations to illustrate the combined effect of the cost risks.

Scenario one: The annual 8% increase of MYPD3 will be applicable. For carbon tax, it is assumed that the additional trade and offset allowance is applied and the environmental levy is removed from the bill, resulting in an expected 2% increase. Scenario one will be seen as the best-case scenario, with the combined cost risk of 10%.

Scenario two: The annual 8% increase of MYPD3 will be applicable. For carbon tax, it is assumed that the additional trade and offset allowance is applied and the environmental levy is still included in the bill, resulting in an expected 4% increase from carbon tax. Scenario two will be seen as the scenario with the highest risk, being very highly possible with a high consequence price increase of 12%.

Scenario three: The annual 8% increase of MYPD3 will be applicable with reactive power charges throughout the year. For carbon tax, it is assumed that the additional trade and offset allowance is applied and the environmental levy is still included in the bill, resulting in an expected 4% increase. It is assumed that the mining company installed mitigation strategies for the reactive power charges and only a 3% increase is expected. The combined cost risk for Scenario three is 15%.

Scenario four: The annual 15% increase of the initial MYPD3 will be applicable with reactive power charges throughout the year. For carbon tax, it is assumed that the additional trade and offset allowance is removed and the environmental levy is still included in the bill, resulting in an expected 6% increase. It is assumed that the mining company did not install mitigation strategies for the reactive power charges resulting in a 6% increase. A managed ECS price increase of 47% is also included. The combined cost risk for Scenario four is 74%.

Scenario five: The same events for Scenario four are assumed but an unmanaged ECS price increase of 59% is included. Scenario five will be seen as the worst-case scenario with the combined cost risk of 86%.

	Consequence	Probability	Cost risk with related price increases				Total price increase for next year
			Price increase	Carbon tax	Reactive power	ECS	
Scenario 1	Low	High	8%	2%	0%	0%	10%
Scenario 2	High	Very high	8%	4%	0%	0%	12%
Scenario 3	High	Moderate	8%	4%	3%	0%	15%
Scenario 4	Very high	Very low	15%	6%	6%	47%	74%
Scenario 5	Very high	Very low	15%	6%	6%	59%	86%

Table 2.9: Risk scenarios for expected price increase.

The calculated scenarios were applied to the annual consumed electricity of the selected

mining group. It was assumed that the same electricity consumption profile will be followed, resulting in an average annual reduction of 3%. The price increase scenarios are illustrated in Figure 2.22. The minimum increase of Scenario one results in a price increase of 46% by 2017, compared to 2013. It is assumed that the ECS will only be applied for one year and the excess electricity rates related to ECS will only increase 10% annually.

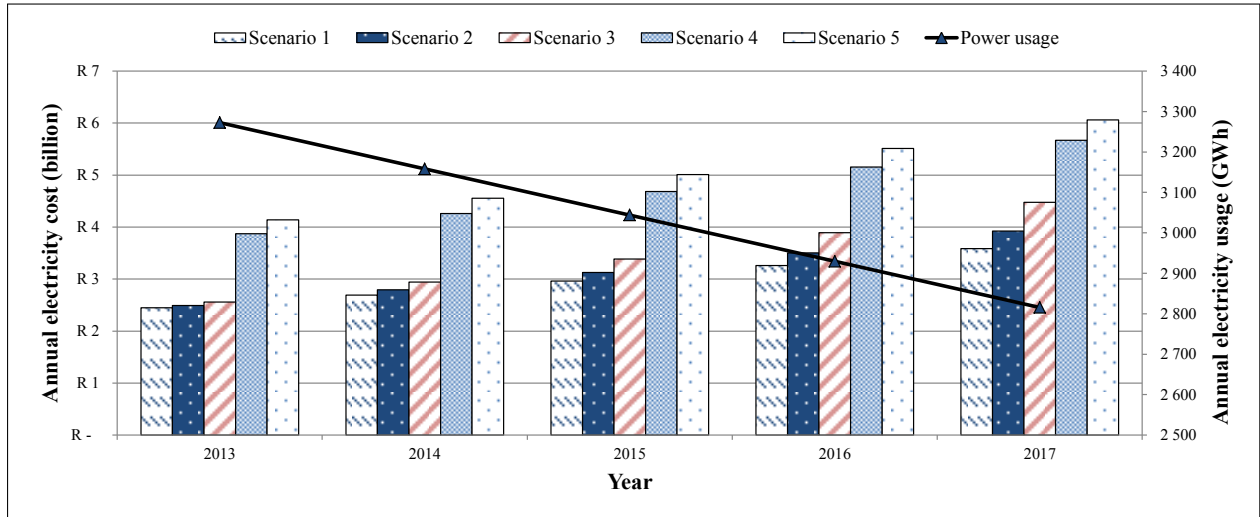


Figure 2.22: Illustration of the quantified risk scenarios.

2.7 Conclusion

In this chapter the four potential identified electricity cost risks related to the mining industry were discussed. The potential price increase equations were derived to provide better insight into potential cost impacts and mitigation strategies. For each cost risk, the relevant cost mitigation strategy was discussed, providing motivation for implementing the infrastructure required to reduce electricity usage.

From the discussed results, it is clear that electricity must be managed according to the rules and reduced to prevent above normal costs. To absorb the highest risk combined increase of 12% (Scenario two), the mine must reduce their electricity usage by 6%, assuming an inflation rate of 6%. The 6% reduction will also protect the mining company against ECS penalties, assuming the baseline usage of 2010 or earlier.

Chapter 3 and Chapter 4 will discuss the possibility of reducing electricity on main mining services. This will provide insight into the potential electricity reduction for the selected mining company.

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