# Dispatching Emergency Reserves

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ISebe leeNjineli kunye neZakhiwo eziSingqongileyo ~ Fakulteit Ingenieurswese en die Bou-omgewing

# DECLARATION

I declare that this dissertation is my own work and that apart from the normal guidance of my supervisor I have received no assistance apart from that which has been stated.

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# ABSTRACT

This dissertation presents the analysis of cost-effective dispatching of emergency reserves with a specific focus on supply and demand side options. On the demand side options the focus is the demand market participation product. On the supply side options the use of hydro and gas specifically the open cycle gas turbines are studied. In capacity constraint systems, supplying the demand with the current generation mix needs to be met. With a diminishing reserve margin and increase in demand yearly this challenge increases. The South African scenario is reported in this paper.

As demand grows the ability to meet that demand remains a focus; a responsibility that remains a priority for the system operator. In times of surplus or shortage generation with adequate or diminishing reserve margins the focus on dispatching optimally and economically is an important aspect. Currently the South African Interconnected Power System is constrained; at times there is more demand than supply.

The reserve categories are the ancillary requirements and are different for all power systems. Reserves are to cater for disturbances on the power system to ensure a healthy frequency is maintained. Reserve categories according to the ancillary requirements are: instantaneous, regulating, ten minute, supplemental and emergency. This dissertation focuses on emergency reserve.

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## NOMENCLATURE, ABBREVIATIONS, KEY GLOSSARY TERMS

| Abbreviation | Meaning |
|---|---|
| AEMO | Australian Energy Market Operator |
| AGC | Automatic Generation Control |
| COUE | Cost of Unserved Energy |
| CSG | China South Grid |
| DMP | Demand Market Participation |
| DWA | Department of Water Affairs |
| EirGrid | Electric Power Transmission Operator Ireland |
| HCB | Hidro Electrica de Cahorra Bassa |
| ILS | Interruptible load shedding |
| IPS | Interconnected Power System |
| MNSP | Market Network Service Provider |
| NEM | National Electricity Market |
| NEMMCO | National Electricity Market Management Company |
| NERSA | National Energy Regulator of South Africa |
| OCGT | Open Cycle Gas Turbines |
| ONS | Operador Nacional do Sistema Electrico |
| PJM | Pennsylvania, New Jersey and Maryland Interconnection, regional transmission organization |
| SONI | System Operator of Northern Ireland |
| TOU | Time of Use Tariff |
| UFLS | Under frequency Load shedding |
| VOM | Variable Operating and Maintenance |

# Chapter 1 - Introduction

## 1.1 Background

Electricity is generated in power stations and transported via the transmission network to a distribution network that delivers it to the end customers. The power system consists of various pieces of equipment to enable this process and to ensure power is supplied where it is needed.

South Africa's electricity industry is vertically integrated with Eskom being the largest electricity industry in the country. Eskom has the responsibility of generating and procuring electricity at generation power plants, transporting it on the transmission network and redistributing it to distributors or directly to the customers.

The System Operator in Eskom, has to operate the interconnected power system (IPS) in a safe, efficient, economical and reliable manner to achieve the highest degree of reliability. It needs to take appropriate remedial action promptly to relieve any abnormal condition that may jeopardise reliability.

The System Operator is responsible for all real-time and near real time operation of the IPS. This includes power trading and wheeling with neighbouring countries. The tasks of the System Operator include ensuring system reliability which comprises of system security and system adequacy [Khatib,1997], emergency and contingency planning, quality and actual delivery of supply 24 hours a day, 365 days a year. Part of this function is the balancing of generation and demand on the IPS subject to the constraints of safety of personnel and equipment. This is done by maintaining and regulating frequency according to the dead band of 49.8 and 50.15 Hz as defined by the Grid Code [Magoro, 2006]. The System Operator coordinates the activities related to generation and transmission of electricity to ensure delivery and quality of power supplied meet agreed standards.

The Grid Code is a document that relates all regulatory and technical requirements for connecting generators, transmission or distribution lines to the power system. This document is maintained and compiled by the Grid Code Secretariat.

As part of its responsibilities to maintain power system reliability, the System Operator is required to ensure the provision of appropriate amount of reserves. The extent of these services and the manner in which they are to be provided is defined in the Grid Code and will follow in later discussions.

Reserves are essential for the management of power system security and adequacy, to facilitate orderly trading in electricity and ensure that electricity supplies are of acceptable quality.

All participants of the IPS co-operate in setting up operational procedures under the direction of the System Operator to ensure proper operation of the IPS.

The robustness of a power system is determined by its ability to withstand unplanned contingencies and disturbances on the network. These disturbances can be network related due to the loss of transmission lines or due to the loss of generation or a combination of both.

In the event of system disturbances there are mitigation measures and protection systems to prevent a complete blackout of the entire South African grid. One such a system is the Under Frequency Load Shedding scheme (UFLS). This is an automatic scheme that drops off load when the frequency rapidly declines below a set frequency namely 49.2 Hz.

This document focuses on the mitigating measures and not the protection mechanisms to deal with frequency decline as a result of a disturbance and more specifically on the dispatching of emergency reserves.

## 1.2 Scope and Limitations

The scope of this dissertation is on the cost calculation of dispatching of the emergency reserves namely open cycle gas turbines, interruptible load shedding, demand market participation and load shedding.

This planning for the 2 week to 18 month period is not part of this dissertation.

Operating reserve and cold reserve is not discussed in detail in the dissertation.

The 60 % load factor would remove the capacity of OCGT's from emergency reserves; this is not discussed in detail on this dissertation.

A very basic approach has been taken to calculate the variable operation and maintenance costs. It would be interesting to explore the VOM cost and to see how it varies as the machines age and the maintenance cost increases. This will not be analysed in this dissertation due to the confidential nature of the information.

For ILS, the cost to the customer, meaning production loss does not form part of this dissertation. It is a limitation as the availability and use of this product is directly influenced by this.

Production loss and other costs to the customer does not form part of this dissertation, it is mentioned but not calculated.

Cost to the country, like the economical impact of load shedding is not considered in this dissertation.

## 1.3 Present conditions in South African Power System

South Africa currently has an installed capacity of over 42000 MW. Demand in South Africa has been growing with no significant generation plant being added to the power system in the last 10 years. As a result the power system has been severely constrained and it has been challenging to meet demand with a steadily declining reserve margin. This has led to the extensive use of more expensive reserves, also termed emergency reserves, to supplement operating reserves in times of capacity shortages.

In 2009 the economic climate in South Africa was healthy, but the world has experienced financial turmoil. In the light of the challenging financial situation globally should Eskom consider more economic dispatch of the emergency reserves? In the light of these capacity constraints and the challenges, the questions arise whether the System Operator has enough tools to make the decisions based on both constraints. If at present only capacity constraint is a guiding factor, should it not become an option to consider economics as well? Are the System Operators empowered and do they have enough tools to make accurate decisions that meet both technical and economic constraints?

Important questions to answer are related to the economics of the emergency merit order that is used to dispatch emergency reserve. Is the emergency reserve which includes the open cycle gas turbines dispatched cost efficiently? Is the emergency reserve dispatch order based on technical or economic constraints or both?

The dispatch rules for the merit order currently assumes dispatching the open cycle gas turbines is very costly and it is therefore last on the merit order. The purpose of this dissertation is to test the validity of this assumption.

## 1.4 Example of typical problem

The open cycle gas turbines are part of the emergency reserve category as defined in the current grid code. At present the system operator is daily required to use the emergency merit order to decide which emergency reserve to use to manage constraints. Two types of constraints exist related to the use of the open cycle gas turbines namely a capacity constraint and a Cape constraint. A capacity constraint occurs when the amount of operating reserves, to meet peak demand, is not enough. The Cape constraint is related to constraint on the transferring of power on the transmission lines to the Cape area, which also requires the use of the open cycle gas turbines.

System operators need to be empowered to manage the power system with increased capacity constraints while focusing on cost efficient dispatching of the emergency reserves to manage the capacity constraints.

In the current context the dispatching of emergency reserves is guided by the merit order. The cost of load shedding is assumed higher than the cost of dispatching open cycle gas turbines therefore it is last on the list. The current situation assumes only the cost of the open cycle gas turbines as pricey and is oblivious to the other costs inherent in using the other emergency resources. The current merit order has some cost based rules associated with it, but it leans itself mostly to the technical needs and shortcomings instead of having a cost reduction approach.

This example illustrates that there are possible alternatives to the existing approaches to dispatching emergency reserves, and leads to the following hypothesis for this research:

***… that a decision on the dispatch of expensive emergency resources, like an open cycle gas turbine (OCGT), can be reduced to a rule-based process consistent with the needs of system operators.***

Testing the validity of this hypothesis requires the following questions to be answered:

- How are reserves defined for the system operator?
- What are emergency reserves?
- What factors affect the reserve dispatch decision?
- What alternative resources are available in the dispatching of reserves decision?
- How are the costs of risk dispatch compared? (What costs are relevant?)
- How are the costs shared between stakeholders?
- What are the indications of actual or impending constraint violation?
- How would the rule be different for another source (e.g. pumped storage?)
- How will you know the result is an optimum solution?

## 1.5 Proposed Methodology

The methodology of testing this hypothesis is based on answering the research questions by review and analysis. A second necessary step is to define the various reserve types and explore the reserve categories for various utilities. The discussion will then follow on the current options employed and defined as emergency reserves on the supply and demand side. The constraints of the various options will be focused on in later chapters to give context to the technical constraints to manage. The cost calculation is aimed at putting numbers to the assumptions. It would then be necessary to do a cost comparison to have a view of which resource is more economical to dispatch.

The ultimate aim is to develop rules that govern how emergency resources are dispatched. This cannot just be entirely based on costs as there are other constraints like dam levels, hours available for the use of certain emergency resources, etc. Constraints will be discussed as a separate chapter to give context to the cost discussion.

## 1.6 Dissertation Structure

**Chapter 1** has introduced the background of the topic and also the hypothesis.

**Chapter 2** is the literature review where the detail research for operating and emergency reserves is studied. In this chapter the research questions as listed in Chapter 1 are also discussed. The system operators reserve definitions from China. Australia, Brazil, Ireland, USA (PJM), Spain and South Africa are studied.

**Chapter 3** discusses the different operating states on the power system and it also defines reserves.

**Chapter 4** defines the timeframes in which the power system should be managed. It lists the four things needed to effectively manage the power system for the day ahead, on the day and instantaneous timeframes.

**Chapter 5** discusses the emergency reserve dispatch merit order. This chapter also deals with the different seasonal constraints (winter and summer) and what the key things are to note.

**Chapter 6** deals with the aspects of the short and long term cost calculation

**Chapter 7** deals with the cost of operating reserves

**Chapter 8** discusses the cost of emergency reserves, specifically the open cycle gas turbines (OCGTs).

**Chapter 9** discusses the cost of demand market participation (DMP), also an emergency reserve.

**Chapter 10** deals with the cost of interruptible loads (ILS) and the cost of load shedding.

**Chapter 11** is a cost comparison of OCGT's, DMP and ILS.

**Chapter 12** summarises the research questions and conclusions

# Chapter 2 - Literature Review

## 2.1 Defining reserves for the system operator

Reserves are needed by the system operator to assist in balancing supply and demand. They cater for deviations in the demand (demand forecast and changes in actual demand) and for deviations in supply (for unplanned generation plant trips and generators not delivering full output). Reserves can be divided into various categories with each category fulfilling a specific function for the reliability and security of the power system. System operators in seven countries were reviewed to determine the different definitions of reserves. The countries chosen for review have diverse conditions in terms of generation mix as well as types of reserves used. It is also representative of all the continents which can highlight the environmental aspect if it does play a role. Countries under review are China, Australia, Brazil, Ireland, USA (PJM), Spain and South Africa.

### China

In China the independent system operator is called China Southern Grid (CSG). The power grid is divided into 6 regional grids [http://en.wikipedia.org/wiki/Electricity_sector_in_China]. The operating frequency is 50 Hz with a tolerance range of 49.9 to 50.1 Hz. The total installed capacity in 2013 was 1247 GW. Coal was at 801 GW, other thermal, natural gas and biomass was at 61GW, hydropower at 280 GW, wind power at 91.4 GW, Solar power at 18 GW nuclear at 15.69 GW [http://en.wikipedia.org/wiki/Electricity_sector_in_China].The peak load in 2011 was 535.5 GWh [Zpryme Smart Grid Insights, 2012].

In China, according to Zhenyong and Yangpo [2011], operating reserves comprise of Load Reserve and Emergency Reserve.

Load reserve is used to meet fluctuations in demand and should be 2 % to 5 % of the expected peak load in the region for the considered period.

Emergency reserves should be available within ten minutes and are to cater for the loss of largest unit (N-1). They are made up of generation and demand capacity, and should be about 10 % of the expected peak load.

## Australia

In Australia's six states the ISO was known as the National Electricity Market Management Company (NEMMCO) with the responsibility of balancing supply and demand by procuring sufficient supply from generation companies [Chand et al., 2002]. It is now known as the Australian Energy Market Operator (AEMO). In 2002 according to Chand it was still referred to as NEMMCO so all information related to the name NEMMCO has been substituted with AEMO.

The generation mix in Australia is 39 % black coal, 24.5 % brown coal, 21 % natural gas, 17 % hydro, wind 7% and 1 % oil and other fuels [AER,2014]. The Australian frequency is regulated at 50 Hz with a tolerance range of 49.9 to 50.1 Hz. The peak load was 37207 MW according to data for 2007. The generation capacity at the time was 47400 MW, representing a reserve margin of 27.4 %. In 2013 the NEM total installed capacity has reduced to 48400MW [http://www.world-nuclear.org/info/Country-Profiles/Countries-A-F/Appendices/Australia-s-Electricity/] and the total demand was 33610 MW [https://www.aer.gov.au/node/9772].

The system operator purchases energy at a wholesale market level and sells it to retailers or directly to the consumer. AEMO purchases reserves to meet demand and to deal with fluctuations and contingencies on the day from the energy market. Generation is purchased from generating companies in the spot pool model market. In the spot pool market energy is sold to the pool and the price is set by the pool. Consumers then draw energy off the pool [Chand et al., 2002].

In Australia operating reserves have been defined as operating states. There are 3 operating states namely reliable, secure and satisfactory as defined by the National Electricity Market (NEM).

The secure operating state means there are enough reserves to withstand the first largest contingency (N-1).

The reliable operating state means there are sufficient reserves to withstand the first and second largest (N-1 and N-2) contingency.

The satisfactory operating state means the supply is adequate but there are not enough reserves to withstand all single contingencies.

AEMO purchases reserves that are adequate to meet the secure operating state [Chand et al., 2002].

In the Australian context reserves are used for frequency control and can be broadly categorised into two main subsets namely regulation and contingency. Regulation reserve caters for supply demand imbalances while contingency reserves caters for any contingency on the grid, as defined by AEMO [2010]

Regulation reserve, also called non contingent, is used to control minor deviations within the normal operating band to the supply demand balance [Chand et al., 2002].

Fast, slow and delayed reserves, also called contingent reserves, are to cater for contingencies and are to restore the frequency to the normal operating band after a contingency.

Fast reserve is capable of responding within 6 seconds of a contingency. It is mostly used to prevent further decay of the frequency.

Slow reserves respond within 60 seconds to a contingency and provide further assistance to bring the frequency to within the normal operating band according to Chand et al. [2002].

Delayed reserve responds within five minutes and provides additional support to bring the frequency as close to 50 Hz as possible.

### Brazil

In Brazil the generation mix is 76 % hydro, nuclear 2 % and thermal 22 % according to Young [2009]. Brazil has an operating frequency of 60Hz. The peak demand in 2007 was 46803 MW and the generation capacity was 96294 MW .The independent system operator is known as Operador Nacional do Sistema Electrico (ONS). In 2001 and 2002 Brazil also had a capacity constraint and had to make use of power rationing methods to curb demand.

The area is divided into four main regions. According to Prada et al. [2002] the Brazilian system has a reserve market where generator agents declare reserve capacity hourly. The price for each reserve is determined by the generator agents. Reserves are procured from the ancillary services market as a service for the system operator.

The Brazilian independent system operator has classified operational generation reserves into four categories namely primary (R1), secondary (R2), tertiary (R3) and quaternary (R4) reserves [Prada et al., 2002].

Primary reserves are for primary frequency control, and relate to the governor response to regulate frequency. This is an automated response of the governors.

Secondary Reserve is used for secondary frequency control and tie line power flow control. It brings the frequency and interface flows to nominal after instantaneous and short term load deviations [Prada et al., 2002].

Tertiary reserves are used to cater for unplanned trips of generators and other plant limitations. It is a spinning reserve allocation for units on automatic governor control (AGC).

Quaternary reserves are used to fill up tertiary reserves and in the event that generators would be out of service for extended periods [Prada et al., 2002].

## Ireland

The Irish power system has two synchronised operating areas. The system operator for Northern Ireland (SONI) operates the power system in the north and EirGrid operates the power system in the south [Young, 2009].

Operating reserves for Ireland are formed with primary, secondary and tertiary reserves [Dudurych, 2009]. Republic of Ireland (South) has a total installed capacity of 7590 MW (6450 MW excluding wind) of which 15 % is wind, hydro is 7 %, thermal and pumped storage. The peak demand for this area is 5084 MW [Young, 2009].

In Northern Ireland the total installed capacity is 2100 MW of which 14 % is wind capacity, the remaining is thermal generation. The peak demand is 1719 MW. The operating frequency is 50 Hz with frequency deadband for both system operators of +/- 15 mHz. Reserves are divided into five main types namely regulating, operating, replacement, substitute and contingency reserves.

The definitions for the different reserve categories are given by Dudurych [2009]. Primary reserves are for primary frequency control and have to be delivered in 5 seconds and maintained for 15 seconds.

Regulating reserve is a subset of primary reserves; it acts within 30 seconds of a frequency deviation within 0.1 Hz of the set point. It also controls the inter system transfer between the North and South interconnector. Secondary reserves have to be delivered in 15 seconds and maintained for 90 seconds. They act to avoid system operation below 49.5Hz

Tertiary reserves are used to replace primary and secondary reserves. They consist of tertiary 1 which restores primary and secondary reserves for the first 5 minutes. Tertiary 2 reserves are available after 5 minutes for an additional 15 minutes.

Replacement reserves acts as a longer term reserve to restore secondary and tertiary operating reserves. This has to be fully available within 20 minutes for a 24 hour period. Substitute reserve is also used to restore replacement reserve after 4 hours for a 24 hour period and is available for the replacement of emissions restricted plant.

Contingency reserve is available to restore all reserves 24 hours after the event.

## USA (PJM Region)

Pennsylvania New Jersey Maryland Interconnection (PJM) is a regional transmission organization that coordinates wholesale electricity operation in all parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and District of Columbia. Installed generation capacity as in 2004 was 163 GW. The generation mix is coal 53.51 %, nuclear 32.84 %, oil 1.97 %, gas 8.5 % and hydro 2.08 % [Young, 2009].

The operating frequency is 60 Hz. The peak demand was 135000 MW.

Four categories of reserves are known namely regulating, contingency (primary), synchronised and supplemental reserves as described by the report by PJM.

Regulating reserve is spinning reserve immediately responsive to automatic generation control (AGC). It responds within four seconds to 5 minutes.

Contingency Reserve is also called primary reserve and is made up of synchronised and quick start reserve.

Quick start reserves are non-synchronised and are available within 10 minutes. They are made up of typically hydro, pump storage and turbines.

Synchronised reserve is online generators that can respond within ten minutes.

Supplemental reserve is also known as secondary reserves and can respond from 10 to 30 minutes. Plant does not have to be synchronised to the system.

Operating reserves for PJM are made up of contingency reserves and supplemental reserves. They cater for load forecast error and generation forced outages.

## Spain

The Spanish independent system operator is known as Red Electrica de Espana with an operating frequency of 50 Hz and the deadband is 200 mHz according to Young [2009].

Spain has two markets namely the energy market and ancillary services markets. The ancillary services market consists of the active power and voltage control market. Under the active market there are load frequency reserves (primary), AGC, tertiary reserves as well as balancing and black start services [Miguelez et al., 2009].

Primary control reserves, also known as load frequency reserves, are used to correct frequency deviations. In the event of a large system disturbance this type of reserve prevents large frequency deviations but it does not bring the frequency back to its scheduled value.

Secondary frequency control reserves or AGC (automatic generation control) is to bring the system frequency to its scheduled value. It also is used to manage the interchange between tie-lines with neighbouring states.

Tertiary frequency control reserves are used to replace secondary reserves. This must be achievable within 15 minutes and is supplied from generators. It has to be sustained for at least 2 hours.

Spain has a 24 hour independent hourly scenario planning, and different markets need to be cleared. The day-ahead market must be cleared before the congestion market. The secondary reserves market is where secondary reserves are purchased and has to be cleared before intraday market is cleared. The tertiary regulation market is to procure tertiary reserves and it has to be cleared before the balancing market is cleared.

### South Africa

In the South African context operating reserves are required to secure capacity that will be available for reliable and secure balancing of supply and demand within ten minutes and without any energy restrictions. Operating reserves consist of: instantaneous, regulating and ten minute reserve. Emergency reserves are not considered part of the operating reserves; they consist of supplemental reserves and emergency reserves. The definition of the types of reserves can be found in the short term energy procedure [Dean, 2009].

Regulation reserve is reserve under Automatic Generation Control (AGC) available to respond initially within 10 seconds and to respond fully within ten minutes. It is used for second-by-second balancing of supply and demand. It is also used to restore instantaneous reserve. It should be available for at least 1 hour.

Instantaneous reserve is generation capacity or dispatchable load reduction available to respond fully within 10 seconds to a drop in frequency. It is activated via direct control at the resource (customer site or generator unit). It is needed to arrest the frequency at acceptable limits following a contingency such as a generator trip, or a sudden surge in load. It is always available for at least 10 minutes. It is fully activated within 10 seconds and is sustained for 10 minutes.

Ten minute reserve is generating capacity (synchronized or not) or dispatchable load reduction that can respond within 10 minutes when called upon, and is available for at least two hours. These reserves are required to balance supply and demand for changes between the day-ahead schedule and real time. It is also used to restore Regulating Reserve after an incident.

Supplemental reserve is used to reduce the short-term risk. It is available for at least two hours and is contracted to ensure an acceptable day-ahead risk.

Emergency reserve is typically made up of contracted supplemental reserve, interruptible load, some gas turbines and emergency generation. It consists of generating capacity or dispatchable load reduction that can respond normally within 10 minutes when called upon and is available for at least two hours. The purpose of emergency reserve is to enable the restoration of frequency to normal in a severe plant shortage situation after all other reserves are exhausted.

The seven utilities studied have different classifications for reserves. Table 2.1 summarizes the classification for the different utilities.

*Table 2.1 Comparison of reserves in Seven Countries*

| System Operator | Generation mix | Reserves | Operating Reserve |
|---|---|---|---|
| **China** | 73 % coal<br>24 % hydro<br>1.5 % nuclear<br>0.16 % other | **Load Reserve**<br>-Non contingent<br>- Demand fluctuations<br>**Emergency Reserve**<br>- Contingent (loss of largest unit)<br>- 10 Min response<br>- Can be generation or demand capacity | Is comprised of Load and Emergency Reserve |
| **Australia** | 56 % black coal<br>24 % brown coal<br>2 % natural gas<br>6 % hydro<br>0.6 % other | **Regulation Reserve**<br>- Non contingent<br>- For demand fluctuations<br>**Fast Reserve**<br>- Contingent<br>- Prevent frequency decay<br>- 6s Response<br>**Slow Reserve**<br>- Contingent<br>- Brings frequency to normal<br>- 60s Response<br>**Delayed Reserve**<br>- Contingent<br>- Brings frequency to normal<br>- 5 Min response | Have operating states, defined as reliable, secure and satisfactory.<br>Reserves categorised into contingent and non contingent<br>Reserves are procured from a market |
| **Brazil** | 76 % hydro<br>22 % thermal<br>2 % nuclear | **Primary Reserve (R1)**<br>-Non contingent<br>-Automated governor response<br>**Secondary Reserve (R2)**<br>-Non contingent<br>-Brings frequency to normal after instantaneous and short term load | R1, R2, R3, R4 are classified as operating reserves |

| | | | |
|---|---|---|---|
| | | deviations<br>**Tertiary Reserve (R3)**<br>- Contingent<br>- Unplanned generator trips<br>**Quaternary Reserve (R4)**<br>- Non contingent<br>- To replenish tertiary reserves | |
| **Ireland** | 29 % wind<br>7 % hydro<br>Thermal<br>Pumped storage | **Primary Reserve**<br>-5 s Response time<br>- Regulating reserves (AGC)<br>- Regulating have 30 s response<br>- Regulating responds for frequency deviation of 0.1 Hz<br>**Secondary Reserve**<br>- To avoid system operation below 49.5 Hz<br>- 15 s Response time<br>**Tertiary Reserve**<br>- To replace primary and secondary reserves<br>**Tertiary 1**<br>- Restores primary and secondary<br>- 5 Min Response<br>**Tertiary 2**<br>- 15 Min response time<br>- Replaces primary and secondary time<br>**Replacement Reserve**<br>- Longer term reserve<br>- To restore secondary and tertiary<br>- 20 Min response time and available for 24 hour | Primary, Secondary and Tertiary are classified as operating reserves |

| | | | |
|---|---|---|---|
| | | **Substitute Reserve**<br>- To restore replacement reserve<br>- After 4 hours restoration time<br>- Available for 24 hours<br>- For replacement of emissions restricted plant<br>**Contingency Reserve**<br>- To restore all reserves<br>24 Hours after the event | |
| **PJM** | 53.51 % Coal<br>32.84 % Nuclear<br>8.5 % Gas<br>2.08 % Hydro<br>1.97 % Oil | **Regulating Reserve**<br>- AGC control<br>- 4s Response time<br>**Contingency Reserve (Primary)**<br>- Made up of Synchronised and Quick reserve<br>- Synchronised reserve<br>- Online reserves<br>- Respond within 10 min<br>- Quick start reserve (non synchronised)<br>- Available within 10 min<br>**Supplemental Reserve (Secondary)**<br>- Respond within 10 min | Contingency and supplemental are classified as operating reserves- caters for load forecast errors and generator forced outages<br>This is a real time operator |
| **Spain** | | **Primary Reserve**<br>- Load frequency reserves<br>- To correct frequency deviations<br>- If large disturbance prevents large frequency deviation<br>**Secondary Reserve**<br>- AGC control<br>- To bring frequency to its scheduled value | Reserves are procured from the ancillary and energy market. |

| | | | |
|---|---|---|---|
| | | - To manage tie line with neighbouring states<br>**Tertiary Reserve**<br>- To replace secondary reserves<br>- 15 Min response time | |
| **South Africa** | 86 % coal<br>5 % nuclear<br>5 % hydro<br>4 % diesel | **Instantaneous Reserve**<br>- Responds to drop in frequency<br>- 10 s Response time<br>**Regulating Reserve**<br>- To restore instantaneous<br>- AGC control<br>- Second by second balancing of demand<br>- 10 s response time<br>**10 Minute Reserve**<br>- Restore regulating<br>- 10 Min response time<br>- Balance supply and demand deviations real time with day ahead<br>**Supplemental Reserve**<br>- 2 Hour call up time<br>- To ensure acceptable day ahead risk<br>**Emergency Reserve**<br>- To restore frequency in severe shortage<br>- 10 Min response time<br>- Only used after all other reserves are exhausted | Instantaneous, Regulating and 10 minute reserves are classified as operating reserves.<br>There is no market for procuring reserves. |

## Key Findings

As per the operating reserves and wind power integration document, several definitions of reserves are given and nomenclature has been developed [AEMO, 2010]. Operating reserve can be defined as that which is needed to balance supply and demand and also to assist with frequency control [AEMO, 2010].

Operating reserves are differently defined for various utilities and some do not have operating reserves specifically defined. Due to the various definitions and categories from different utilities it is not possible to have one defined statement for operating reserves and their composition.

Based on the analysis, reserves can be categorised into two main groups namely contingent and non contingent.

Non contingent reserves are for response to demand deviations. The response time of this type of reserve is seconds.

Contingent reserves respond to a system disturbance, for example a unit trip or a transmission plant trip. In the contingent category, reserves are needed for two restoration purposes namely to arrest frequency decay and to restore frequency to nominal.

There's also the concept of primary, secondary and tertiary reserves which is different for each utility.

Primary reserves are mainly AGC and are automated response of plant to small frequency deviations. In utilities with interconnectors to neighbouring states, the primary reserves also correct deviations on the tie line. South Africa does not use the word primary reserves even though it is accepted that instantaneous and regulating are both considered as primary reserves [Dean, 2009].

Secondary reserves are to deal with frequency arrest and to stop frequency decay. For Brazil however secondary reserves are to restore the frequency after demand deviations and tertiary reserves are a type of contingent reserve for unplanned generator trips [Prada, 2002]. Brazil has 70 % hydro plant in its generation mix [Zhenyong and Yangpo, 2011]. This could be significant as hydro has a quick response hence the different classification of the primary, secondary and tertiary reserves.

Tertiary reserves are in most utilities to replenish primary or secondary reserves.

In Australia the category called delayed reserves is similar to ten minute reserves in the South African context. Brazil also has a category called tertiary reserves which is similar to the ten minute reserve category in South Africa.

There are utilities like Ireland and Brazil that categorise replacement and substitute reserves as well. Replacement reserves are to replenish the tertiary and secondary reserves categories for

Ireland and Brazil [Prada et al., 2002]. Substitute reserves as defined by Ireland are for the replacement of all types of reserves within 24 hours [Dudurych, 2009]. It seems that these types of reserves perform a similar function to emergency reserves even though the time frames and conditions under which they are dispatched differ.

## 2.2 What are emergency reserves?

The concept of emergency reserves is not prominent in any of the utilities studied. China has a category called emergency reserves [Zhenyong and Yangpo, 2011] but it fulfils the same function as secondary reserve response. It is a contingent reserve as per the Chinese system operator [Zhenyong and Yangpo, 2011] but Ireland does have a similar concept called replacement or substitute or contingency reserves. These types of reserves are to replenish tertiary, secondary or all types of reserves [Dudurych, 2009].

Whereas with the other utilities the reserves categories still form part of operating reserves, in the South African context the emergency reserves is not part of the operating reserves category [Dean, 2009].

Zhenyong and Yangpo [2011] state that the Chinese system operator also uses emergency reserves.

Thompson [1999] defines emergency reserve as that which is obtained once not enough generation is available and the existing running machines are expected to produce more output. Work done by Thompson [1999] reflects the different outputs for machines run at higher than maximum continuous rating (MCR).

Sullivan [1996] confirmed that emergency reserve is that which is on existing running plants at more than MCR output. Both these works were done in 1996 and 1999, the relevance is that it seems this concept used to be popular before the market concept. Much work has been done in the reserve field now.

South Africa has for some reason stayed with the definitions of emergency reserves.

## 2.3 Alternative resources to be considered in the dispatch decision

Alternatives to be dispatched as reserves can vary from options on the generation side to demand side.

In South Africa emergency reserves are dispatched when all other resources have been depleted [Dean, 2009]. These reserves are not considered as part of the day-ahead reserves plan, and are deployed in extreme plant shortages.

The alternative resources to be dispatched as discussed by Heffner [2007] are replacement reserves. In the Nordic region, for example, alternatives for this category are gas turbines. It is a requirement that the minimum requirement of replacement reserves be met and over and above that gas turbines usage also needs to be procured. Nordic also has different options depending on seasons. Hydropower usually provides regulation reserves but during winter when capacity is tight then it is procured from Elspot market [Heffner et al., 2007].

Alternative options for China are defined as long term reserves. Reserves are distributed to each control area. Long term reserves are defined here as reserves that can be called upon within 2 hours [Heffner et al., 2007]. They consist of all spinning reserve, hydro stopped units and standby gas/oil turbines. In the event of a severe power shortage support from control areas are called upon to assist with additional capacity. The use of demand options on the smart grid as reserves is also explored. The idea is that apparatus in the house will respond to frequency deviations and be disconnected from the grid at certain frequency levels [Zhenyong and Yangpo, 2011]

Australia has a market based system and reserves are procured in the energy market [Australian Power Exchange Operations, 2002]. Reference is made to generation being purchased but the types of options are not listed. It is also mentioned that demand side options are of a passive nature where the customer does not bid but is prepared to switch off machinery to reduce cost [Chand et al., 2002].

Alternate options in Brazil are from the supply side with generators providing additional capacity. 90% of the Brazilian generating capacity is hydro. Independent power producers and industrial consumers are mentioned but it is not clear that Brazil has any other options in terms of reserves [Prada et al., 2002].

Ireland does indicate that it has different types of generation mix and up to 43% as gas [Dudurych, 2009]. Ireland does have a large portion of wind penetration but this is unreliable and cannot be considered as part of the operating reserve category. According to Dudurych [2009] Ireland has a demand side program with 3 different parts. There is a winter peak demand reduction program that was introduced in 2003/2004 with a focus on industrial and commercial customers to reduce electricity use during peak hours (from 5-7) in the winter months. The second program is the Powersave scheme. Large and medium size customers participate and reduce consumption on days when supply and demand is matched. Customers are paid based on reductions achieved per year. A Powersave event may be called any business day of the year or any time of day. There are rules governing these events [Thompson et al., 1989]. A third option is the Short Term active response. Consumers are contracted and compensated to make their load available for short term interruptions. This scheme was previously known as the interruptible load scheme. This scheme provides the system operator with contingency reserves (in the event of a generator trip). Up to 10 to 20 unplanned interruptions can be expected per year each lasting up to 5 minutes.

Options available for PJM are generation or customer demand response. On the generation side the options range from the run of river hydro, pumped hydro or combustion turbines or diesel type units [PJM State and Member Training Department, 2011].

In Spain the options are mostly from generators [Miguelez et al., 2008].

In South Africa demand market participation (DMP), hydro, diesel fired turbines and interruptible load form part of the additional options to be considered [Dean, 2009].

## 2.4 What factors affect the reserve dispatch decision?

According to the earlier classification, reserves are either non contingent or contingent. Non contingent reserves are dispatched based on demand deviations for most utilities. The response time for these reserves is seconds.

Contingent reserves are only dispatched when a contingency occurs. These reserves get dispatched in the event of an unplanned generator outage or the unexpected increase of load. The response time for these reserves depends on the severity of the incident and can be within seconds or minutes. This means that a contingency affects the dispatching of reserves.

Replacement reserves are to replenish non contingent reserves. In Australia the slow and delayed reserves [Heffner et al., 2007] have been listed as part of the replacement category. It is dispatched when secondary and tertiary reserves have been depleted [Heffner et al., 2007]. It is not clear from the literature whether it is automated or as dispatched by the system operator.

Heffner et al. [2007] did an international comparison for Australia, Nordic Region, United Kingdom (National Grid), Texas (ERCOT) and Mid- Atlantic (PJM) on loads providing Ancillary Services. In this discussion parameters affecting the dispatching of contingent and non-contingent reserves are discussed as well.

The parameters affecting the dispatching of reserves according to Heffner et al. [2007] are listed as:

- the minimum run time of units,
- minimum off times,
- minimum load,

- ramp time for spinning reserves,
- accommodation of inaccurate response
- and the limiting regulation range within the operating range for coal plant.

These parameters will have to be considered and discussed in more detail with a specific focus on the dispatching of emergency reserves [Heffner et al., 2007].

AEMO (Australia) has a process whereby additional operating reserves can be procured if reserve shortfall is forecasted for a peak season. It can be procured from loads or generation capacity. In Australia the shortfall in meeting demand affects the dispatch decision.

Other factors affecting the reserve dispatch decision are the constraints on the reserve resources. In South Africa the use of hydro over the open cycle gas turbines or any demand reduction is dictated by the availability of the resource.

## 2.5 Period of operation considered related to decision to be made

From the literature [Heffner et al., 2007] it seems as if most markets do a day ahead or on the day analysis to determine the sufficiency of reserves. The literature is silent on the period of operation that needs to be considered. The South African case will be discussed in the theory chapter. For different periods the decision that needs to be made takes different things into account. The system conditions, seasons of the year and availability of diesel, water or DMP to make an accurate decision on which resources to dispatch. The limitations of the various options the constraints, the risks, will be discussed in the theory chapter.

## 2.6 Costs of risk and dispatch comparison

In all of the utilities studied except South Africa, reserves are traded via a market. In the market context costs of risk compared to dispatch can be analysed. The cost of these ancillary services varies per utility. Procurement of ancillary services is a two-step process in many markets. Heffner et al. [2007] studied five electricity markets. The cost of dispatch is listed but not compared to risk. The risk associated is the possible frequency decline that can lead to system collapse. Depending on the market and system operator structure, cost sharing between stakeholders varies. In Nordic, there are five system operators and costs are shared amongst the five utilities [Heffner et al., 2007].

From the literature review not much work has been done in this field. China did work in the risk evaluation [Sullivan, 1996]. This work only is relevant to evaluating the risk and does not compare the cost of dispatching with the cost of risk.

Heffner et al. [2007] gave an overview of different markets where the cost of dispatching reserves for Australia gets discussed.  From the key findings it has been concluded that for the cost of providing ancillary services for the five markets studied was about 2 – 3% of the total monetary value transacted. The markets studied were Australia, United Kingdom, Nordic Regions, PJM and Texas.

No literature that compares these two concepts could be found. More work will be done in the theory chapter specifically for emergency reserve dispatching.

## 2.7 Costs sharing between stakeholders

Heffner et al. [2007] showed in each market how costs are shared amongst stakeholders.
For Australia there are three formal market participants. Australia has a spot pool market. Market Generators sell capacity through the spot market and receive spot price as settlement. Market Network Providers can as Transmission Network Service Providers (TNSP's) and Distribution Network Service Providers (DNSP's) are regulated entities who cannot participate in the electricity market in Australia and obtain their network revenue from regulated network charges paid directly by market participants rather than being recouped from the spot market. Only Market Network Service Providers (MNSPs) and generators receive their revenue from the electricity spot market in Australia. However there is only one MNSP (Basslink) still operating in Australia with all other transmission and distribution entities being regulated TNSP's and DNSP's and Distribution Network Service Providers) own and operate networks and pay participating fees and obtain revenue from trading. Market Customers purchase electricity; these include distributors and end use customers [Heffner et al., 2007]. It is the system operator, AEMO's, responsibility to purchase reserves from Market Generators in order to balance supply and demand.
PJM has more than one market operating namely day ahead, real time energy, daily, monthly and multi monthly capacity. PJM market participants have two options: to be dispatched centrally or to self-dispatch. This is on a day-ahead basis. If there are shortfalls in the self-dispatch generation, PJM balances this in the real time market. The costs are varied for the different market participants [Heffner et al., 2007].
In the South African context the System Operator is vertically integrated so the costs are one cost to the company even though it has separate divisions. The stakeholders in this case are the generation pool, demand reduction participants and the system operator. The cost sharing will be discussed in the theory chapter.

## 2.8 Indications of actual or impending constraint violations

Constraint violations for system operators are different depending on the generation mix, geography, climate, etc. According to Heffner et al. [2007] the utilities studied have an energy imbalance management market. Energy imbalances are dealt with on day-ahead and real time auctions. In this way any forecasting or scheduling shortfalls and network congestion difficulties are resolved. From this work it seems as if most utilities deal with shortfalls or impending constraint violations day ahead via auctions or trade [Heffner et al., 2007].

In the United Kingdom a physical balancing mechanism is used to trade within the hour for constraint violations.

In the Australian market generators submit a schedule day ahead which AEMO uses to determine which generation mix to use.

Nordpool maintain a mix of dispatchable operating reserves. It also has a regulation power market that reserves certain amount of capacity to provide last minute reserves for balancing.

ERCOT operates a real time balancing market that accounts for 5-7% of the total energy scheduled by ERCOT. It looks at the balance between supply and demand and as necessary will buy additional balancing if needed.

PJM has the ability to arrange for additional reserves during hot or cold weather alerts. An instantaneous reserve check is used to determine if reserves are adequate. If shortages exist then emergency procedures are activated. This check is performed day ahead or can be performed prior to peak as needed [Heffner et al., 2007].

In summary all the utilities have markets where reserves are traded. For South Africa this will be discussed in chapter 3 as no market exists and constraints are experienced regularly. South Africa does have technical constraints and violations are indicated by alarm systems.

## 2.9 Different rules for different resources

The rules for dispatching different resources depend on what is bid in the markets [Heffner et al., 2007]. Cost determines most of the rules for the resources acquired. For South Africa the case of all the various options like open cycle gas turbines, DMP, hydro and running plant at emergency levels will be discussed later. The rules for these resources will not necessarily be cost related. More details on this in the theory chapter.

## 2.10 The result and optimum solution

An optimum solution is utility specific and no one particular solution fits all. It has already been mentioned that because the South African electricity industry is vertically integrated and no market exists, most of the work applied cannot be used in this context.

An optimum solution for PJM for example is to have two ancillary services markets to trade reserves. For the Nordic pool which connects four different countries an optimum solution is to have a day ahead and intraday market. There are no fast and hard rules, and the optimum solution depends on the utilities generation mix and geography.

## 2.11 Transfer Pricing

Transfer price is an interdivisional cost or charge [Drury, 2011]. It is the price at which goods or services are transferred between units in the same company. Transfer pricing is used to encourage optimal performance. It can be based on marginal cost or full cost or market price or negotiations. The criteria need to be met, namely equity (must be a fair measure of divisional performance), neutrality (it must avoid any distortion of business decision making) and administrative simplicity. This is an artificial selling price that enables transferring division to earn return for their efforts. An ideal transfer price should reflect opportunity costs. The opportunity cost of transfer can be an external market price, or the external market price less savings in selling costs. Cost based approaches are used in practice where there is no external market for the product being transferred or if the external market is imperfect due to limited external demand [Drury, 2011].

## 2.12 Allocation Costing

Cost allocation is a method that assigns cost of services provided to the users of that service [BPP learning Media, 2009]. It does not determine the price of the service, but rather what the service costs providers. It can be made up of direct or indirect costs. Cost allocation is the process of assigning costs when a direct measure does not exist for the quantity of resources consumed by a particular cost object. It involves the use of surrogate rather than direct measure. The basis that is used to allocate cost is called an allocation base. Direct costs are assigned using cost tracing whereas indirect costs are assigned using cost allocations. Two types of systems can be used to assign indirect costs namely traditional and activity based cost (ABC) system [BPP learning Media, 2009].

Traditional systems were developed in the early 1900s and rely extensively on arbitrary cost allocations [BPP learning Media, 2009]. ABC systems were only developed in the late 1980 and use the cause- and- effect cost allocations. ABC systems have a larger number of cost centres and a greater number and variety of cost drivers/allocation bases in the allocation process. Overhead costs are assigned to each major activity rather than departments which normally represent cost centres with traditional systems [BPP learning Media, 2009].

In the next chapter operating states and reserves are defined.

# Chapter 3 – Defining Operating States and Reserves

The integrated power system (IPS) has various states including the normal and abnormal states. In the abnormal state different pre load shedding states have been defined as well. These pre load shedding states indicate the severity of the emergency once all reserves have been used and the only option remaining is power rationing or load shedding.

## 3.1 Operating States for Eskom

### 3.1.1 Normal State

The power system is in a normal state when the following conditions are met:

- Sufficient operating reserves are available to deal with any incidents and demand deviations on the power system.
- The frequency is in the normal operating bandwidth of 49.85 to 50.15 Hz.
- The interconnections with international neighbouring utilities are intact.
- Generation is dispatched according to the daily hourly dispatch schedule as far as is possible.

In the normal state, the use of the emergency reserves is not needed because there are sufficient operating reserves.

### 3.1.2 Abnormal State

The power system is in an abnormal state when the conditions in the normal state are violated. Emergency reserves will be dispatched under the abnormal state to replenish the operating reserves.

The use of the emergency level conditions indicates that the power system is constrained and that there is not sufficient generation to meet demand and reserves. The abnormal state is then also a type of emergency state as emergency reserves and conditions are activated in this state. The abnormal state needs a more clear definition. There is also an emergency state that has 3 defined levels. This state also needs a definition that is aligned with the abnormal state. It is evident that there are not enough states defined to cater for all the actual operating states the system operator operates in. A review of the power system operating states is needed.

### 3.1.3 Emergency state

Another state exists called the emergency state. This state is declared when there is not enough capacity to meet demand and a load reduction (load shedding) is needed to manage peak demand. This state has 2 preceding levels of alert before the actual emergency state is declared. The early warning is an alert type when the power system is 1200 MW away from the emergency state. The alert phase is when the power system is 600MW away from an emergency being declared. The alert types was introduced to give a sense of warning before the declaration of an emergency state which means load shedding starts.

In the emergency state the assumption is made that all emergency reserves have been dispatched in the abnormal state. The calling of the alerts to indicate the imminence of load shedding can be challenging both from the accuracy and also from calling it timeously. This can lead to the inaccurate declaration of an emergency on the power system.

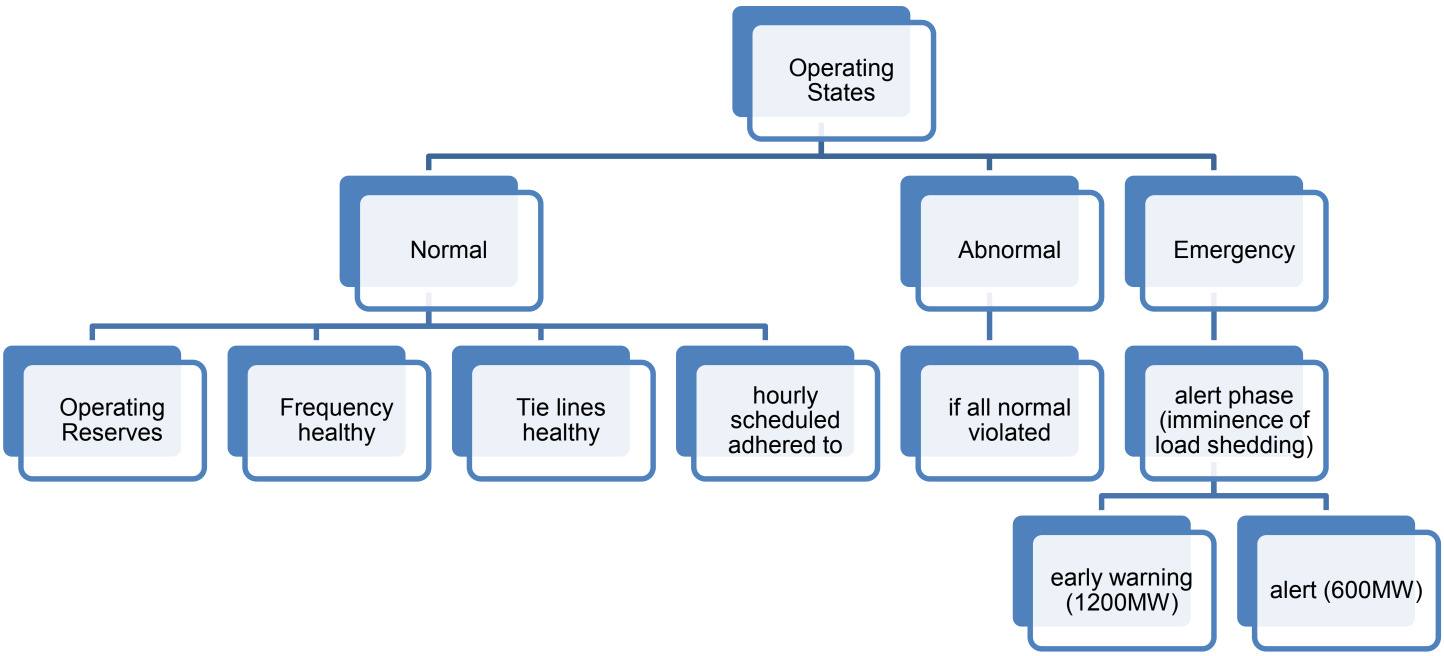


***Figure 3.1 Operating States summarised***

## 3.2 Defining Reserves

The power system needs to have enough operating reserves to cater for any inaccuracies and deviations from the load forecast, changes in demand and any unplanned unit trips or losses. Not managing the supply and demand balance and transmission line outages could lead to a partial or complete system collapse.

Various categories of reserves exist in the South African context. Categories of reserves are cold reserve, supplemental reserves, operating and emergency reserves.

### 3.2.1 Operating Reserves categories

Operating reserves are that generation needed on the power system to cater for unplanned generation loss or deviations in demand. Analysing the research done in chapter 2, the results and key themes are as follows:

Operating reserves are to cater for demand fluctuations, load forecast errors and unplanned generator unit trips. Operating reserves can be classified as contingent and non-contingent reserves. Most utilities, specifically the ones studied have AGC as an automatically dispatched reserve to regulate small frequency deviations. There exist categories called replacement, substitute, contingency and emergency reserves. Replacement reserves replenish operating reserves and some utilities define this type of reserves as part of the operating reserve category. Substitute and contingency reserves are to replenish all other reserve and this reserve does not form part of the operating reserve category at all. This could be similar to a type of emergency reserve category as defined in South Africa.

From studying the literature in chapter 2 the table below gives a summary of the operating and additional reserves categories for different utilities.

***Table 3.1 Reserve Category list***

| **System Operator** | **Reserve list** | **Operating Reserve classification** | **Additional Reserves** | **Function of reserves** |
|---|---|---|---|---|
| China | 1. Load<br>2. Emergency | Load reserve and emergency reserve | | • To deal with demand fluctuations and contingencies(trip of a generator) |
| Australia | 1. Regulation<br>2. Fast | Use operating states, classify reserves only as contingent and | | • Operating reserves are used to manage demand fluctuations |

| | | | | |
|---|---|---|---|---|
| | 3. Slow<br>4. Delayed | non-contingent | | • It also prevents frequency decay<br>• Bring frequency to normal after a contingency(generator trip) |
| Brazil | 1. Primary<br>2. Secondary<br>3. Tertiary<br>4. Quaternary | Primary, secondary, tertiary and quaternary | | • Operating reserves are used to manage demand deviations,<br>• To bring frequency to normal after generator trips or deviations.<br>• Quaternary is part of operating but is used to replenish tertiary(which caters for unplanned generator trips) |
| Ireland | 1. Primary<br>2. Secondary<br>3. Tertiary<br>4. Replacement<br>5. Substitute<br>6. Contingency | Primary, secondary and tertiary reserves | Replacement, substitute and contingency reserves are to restore all other reserves | • Operating reserves are used to regulate the frequency for any 0.1 Hz deviations and to avoid operation below 49.5 Hz.<br>• Replacement reserves is to restore secondary and tertiary reserves<br>• Substitute reserves is to restore replacement reserves<br>• Contingency reserves restore all reserves. |
| PJM | 1. Regulating<br>2. Contingency<br>3. Supplemental | Contingency and supplemental | | • Operating reserves caters for load forecast errors and generator forced outages. |
| Spain | 1. Primary<br>2. Secondary | Primary, secondary and tertiary reserves | | • Operating reserves are to correct frequency deviations |

| | | | | |
|---|---|---|---|---|
| | 3. Tertiary | | | • To bring frequency to nominal value. |
| **South Africa** | 1. Instantaneous<br>2. Regulating<br>3. 10 minute<br>4. Supplemental<br>5. Emergency | Instantaneous, Regulating and 10 minute | Emergency and supplemental reserves form part of the emergency reserve category. | • Operating reserves are to cater for demand deviations, load forecast errors and generator trips.<br>• Emergency reserves are to be used if the operating reserves are not enough |

From the table the general uses of operating reserves are to cater for demand deviations, load forecast errors and generator trips. It also is used to arrest frequency decay and to restore the frequency to nominal after a disturbance.

Some utilities have replacement reserves that replace the primary and secondary reserves when they are depleted. Ireland for example has categories that replace all reserves.

In the South African context operating reserves consist of instantaneous, regulating and 10 minute reserves.

Instantaneous reserve caters for a drop in frequency due to generator trip and can be a generation capacity or a demand reduction. This type of reserve must be able to respond within 10 seconds. This type of reserve could also be classified as a contingent reserve as per the definitions above. Regulating reserve is an automatic generation control and is used to balance generation and demand. This type of reserve is needed to restore frequency after an incident of demand or generation change.

Ten minute reserves are needed to restore regulating and instantaneous reserve. This type of reserve must be able to respond within 10 minutes and be available for 2 hours. It could also be classified as a replacement reserve as per the definitions in Table 2.

The operating reserve requirement is determined by the System Operator. It is calculated annually for the following year. The calculation of the operating reserves excludes the emergency reserves scheduling. The system operator is responsible for ensuring all types of reserves are planned and supplied.

### 3.2.2 Emergency reserves categories

Emergency declarations have different meanings and conditions in the Eskom context. Emergency level 1 is that state, where certified generators run above maximum capacity for up to 3 hours to provide extra generation. This state is also necessary to have access to the expensive emergency OCGT's and using the hydro plant out of scheduled hours. This is a regulatory requirement and is part of the prudency test for operating the power system optimally and cost efficiently. This state is the first sign that emergency reserves will be called upon and that there are no operating reserves.

Emergency level 2 used to be in use but is no longer used and is similar to emergency level 1 in that the same generators are run for longer at above maximum capacity rates. This state caused extensive damage to the generators.

The declaration of a system emergency is needed before load shedding is done. This state is declared once all resources (all emergency reserves) have been used.

According to the literature study in chapter 2, the emergency reserve concept and term is not widely used by other utilities. China does use emergency reserve but it forms part of their operating reserves. No other utility uses the emergency reserve concept but the contingent reserve concept is widely used.

South Africa has a vertically integrated electricity industry, is on the southern part of Africa and virtually isolated from international neighbouring utilities. Little support from neighbouring utilities makes the frequency deviations much more severe and no support is available from neighbouring utilities during a complete blackout.

South Africa is the only utility where the emergency reserve is a type of replacement reserve. From the literature review it is clear that emergency reserves are used in South Africa when no operating reserves is available. It is not a 10 minute or regulating type of reserve so, it replenishes the reserve categories as listed in the South African context. Emergency reserves are not considered as part of the operating reserves.

The emergency reserves are dispatched based on the day-ahead risk assessment. If the day-ahead risk indicates operating reserves of less than 1000 MW (2.85 %), it is most likely that emergency reserves will be utilised. Emergency reserves consist of gas or diesel generation, extra hydro generation or the usage of existing plant to be run at maximum or higher than maximum capacity and customer reduction (DMP). The emergency dispatch merit order guides the order of usage of these emergency reserves.

Supplemental reserves form part of the emergency reserve category. Supplemental reserve is generating capacity or dispatchable load reduction that can respond within a notice period up to six hours to restore the other reserves. The purpose is to ensure an acceptable day-ahead risk especially over the daily peaks.

To get access to emergency reserves, an emergency level 1 has to be declared, which implies certified plant are run at more than maximum capacity. It appears as if the reserves dispatched after this condition has been declared were then termed emergency reserves. They could be known as replacement or substitute reserves as well. Emergency reserve is typically made up of supply and demand side options. Some emergency reserve may take up to one hour to respond. Emergency reserves cater for any unplanned events.

There are some rules for dispatching emergency reserves in South Africa even though they are not formalised, functional and adequate to cater for the various power system conditions. This dissertation explores the possibility of a rule based method to dispatch emergency reserves in South Africa.

#### 3.2.2.1 Supply side options used as emergency reserves

Typical examples of supply side options used as emergency reserves include when generation is increased by running additional generation plant or running the existing plant above its nominal rating.

Some certified generators (mostly coal fired and some pump storage plant) runs above nominal for additional capacity. This would normally be the first step in dispatching on the emergency dispatch merit order. The constraint with this option is the wear and tear on the machines. The plant can potentially be exposed to a higher unplanned failure rate.

The use of hydro plant outside of its scheduled hours as agreed with the Department of Water Affairs (DWA) is part of the additional generation that can be used under emergency conditions. The constraints with this option are the amount of hours available as released by DWA and also environmental constraints like a drought. When there is a drought the amount of water for release gets restricted. This means that the amount of hours to run the hydro plant also gets restricted.

Municipal generation plants in the form of gas turbines can be run on request by the System Operator when capacity is constrained.

Neighbouring country utilities also have gas turbine plant that can be run in the event of an emergency. The constraint with this option is the availability of fuel (diesel) and the condition of the plant. These plants are run only once the open cycle gas turbines have been started.

The other option is the running of the open cycle gas turbines for additional capacity.

#### 3.2.2.2 Demand Side options

The options for demand side reserves are currently the demand market participation program (DMP) and interruptible load products. There are pilot projects like the utility load management and residential load limiting products that could be included in this category in future.

Demand side supplemental reserve from Demand Market Participants normally responds in less than 2 hours. The second option in this category is the interruptible loads shedding (ILS). This is a load reduction of a large industrial customer. The constraint with this product is the recovery time and the hours available to use it.

The order of use of the emergency reserves is indicated in the emergency merit order as discussed in Chapter 5.

# Chapter 4 – Different time frames to manage the South African Power System

The power system is managed within the following time frames: 2 weeks – 18 months ahead (planning), day ahead, on the day and instantaneous. The time frames require the same parameters but due to the time frames the focus is not the same.

The demand forecast, the capacity available and the operating reserves are fundamental to ensuring safe and reliable operation of the power system. The discussion that follows builds the time frames concept; key matters and questions are discussed to enable operators to make good decisions in managing this intricate balance.

The first time frame is real time – it is defined as the on-the-day (24 hour) period and includes the instantaneous time frame (real time).

The second is the day-ahead (24 hours prior to on the day) to rolling week-ahead time frame which has a focus of managing semi future events.

The third is the week ahead to month ahead timeframe which is significantly looking into the future to manage events.

In each of these contexts knowing the demand, having sufficient generation and having enough reserves (operating and emergency) are key to ensuring security and reliability of the IPS.

## 4.1 Day Ahead Time Frame (24 hours before actual day)

The day-ahead time frame is within the decision space of the generation scheduler and the generators. This means that the whole process and procuring of reserves and capacity is entirely the generation scheduler's function. The planning of the next 24 hours is about ensuring enough capacity is available and if not the necessary emergency reserves should be scheduled. There is a gap in this process in that the bidding and schedule is finalised at 10 am previous day and any changes after this time are not incorporated into the day-ahead schedule, including definite inaccuracies in terms of the hourly generator schedule. In fact the day-ahead schedule is probably not valid at the time of implementation starting at 00h00 the following day. It also implies that there is no process of rescheduling in place to cater for contingencies a day ahead. On the day rescheduling is currently being developed as a result of the gap highlighted due to this dissertation.

### 4.1.1 Capacity Available to Meet Demand

The capacity and reserves available day ahead are scheduled to meet demand as per the hourly load forecast provided. This capacity comprises of base load generation, self-dispatched generation and peaking plant as well as demand reduction from the demand market participation program. In addition reserves are also scheduled.

Base load generation is obtained via a bidding system where generators bid hourly capacity as well as operating reserves available to meet demand. Peaking plant is scheduled as needed during the peaks of the day (morning and evening). If operating reserves are not sufficient, then emergency reserves will be used.The generation scheduler will schedule available DMP and the rest of the emergency reserve dispatching is dispatched on the day as per the operators' discretion.

The schedule for self-dispatched generation is provided by the generator. This is non dispatchable by the system operator. The day-ahead hourly schedule is finalized at 10 am previous day.

The shortfall per hour is calculated day ahead and should there be a shortage of operating reserves, emergency reserves in the form of demand reduction or additional generation will be contracted to meet this.

The process of ensuring enough capacity and reserves are available to meet demand is the responsibility of the generation outage scheduler. There is no operator involvement in the day-ahead process.

#### 4.1.2 Operating and Emergency Reserves

Operating reserves are procured via ancillary services as scheduled by the generation scheduler and, if they are not sufficient, additional emergency reserves will be procured to meet demand. This could be a gap and an opportunity for the real time operator to be included when the operating reserves are reviewed.

Emergency reserves are dispatched by the real time operator on the day. The demand reduction emergency reserves identified by the generation scheduler are dispatched day ahead. The costs associated with these emergency reserves (specifically OCGT's) are assumed to be very high and is only needed when the power system is in an abnormal state. An abnormal state is when the operating reserves are less than the requirement and when the frequency is lower than 49.8 for 10 minutes and longer.

### 4.2 On the Day – Real Time

In real time the important factors are the reserves (operating and emergency), the capacity available to meet demand and the load forecasted demand. The significant changes to the hourly schedule produced day-ahead are not accounted for, which poses a risk to the on the day operations. Due to the fact that no rescheduling day ahead or on the day or any balancing mechanism is in place, the day ahead hourly schedule is technically not valid from the time of contingencies on the power system. This means that even the scheduling of peaking plant day ahead is inaccurate as changes are not catered for. Should the scheduling of peaking plant be done daily by the operator? How many times should rescheduling happen in the day ahead and real time context?

### 4.2.1 Capacity Available to Meet Demand

This is obtained from the hourly schedule that was produced day ahead. Nothing can be done on the day to increase this capacity except for plant returning from outage. In real time the operator is only concerned about the capacity currently on line to meet demand and the highest peaks of the day. In the morning and evening when peak is experienced, peaking plant will be used to supplement baseload generation. The management of this resource is a trade-off between the constraints of all the available resources.

### 4.2.2 Managing Demand

The demand is as obtained by the average hourly forecast provided.

To meet morning and evening peak the shortfall is calculated based on current capacity and peaking plant is included in this capacity. Emergency reserves are scheduled if not enough operating reserves are available.

The operating reserve scheduled day ahead is re-evaluated to determine if it is sufficient. The real time operator needs to make a decision on which emergency reserves to dispatch in the event of a shortage.

The emergency reserves are dispatched according to the merit order. The merit order discussion is in section 5.2.

One of the gaps in this method is the re dispatching when generation changes have occurred. It would assist the operator if a real time dispatch is deployed to re dispatch when changes on generation or demand have occurred. Another gap is the dispatching that focuses only on peak periods, which should focus on an hourly dispatching and would need to have a post-dispatch analysis to determine the efficiency of the dispatching.

### 4.2.3 Instantaneous Timeframe

The instantaneous timeframe, looking at the current instantaneous demand, has the same rules as for the on the day timeframe. The shortcoming here is that the load forecast is an average hourly value. The highest peak of the day is the instantaneous highest demand that must be met. This in itself poses a challenge to the operator as his planning is to meet instantaneous demand and no forecast is available for that.

The capacity shortage is calculated based on the hourly average forecast value. The operator would then assume the instantaneous demand to determine how much additional reserve is needed if the operating reserves are not sufficient. It would be useful if the instantaneous demand is forecasted, this will enable the operator to make a more accurate decision on how much is needed to manage the highest demand of the day.
In chapter 7 the cost of operating reserve is discussed.

# Chapter 5 - Emergency Reserve Dispatch Merit Order

Managing peak demand is about ensuring enough capacity and operating reserves are available and if not then the emergency reserve dispatch merit order will be used.

## 5.1 Managing Peak Demand

In the South African context seasonally the highest demand period is in winter (June – August). The demand for weekdays (Monday – Thursday) is higher than for weekends (Friday – Sunday). Typically the highest demand of the day is experienced in the evening with the exception being a Friday. In winter the evening peak is highest for a Friday whereas in summer Friday morning peak is the highest.

The managing of the peak demand for winter and summer periods requires different operating philosophies. Management decisions guide the maintenance strategies for winter and summer.

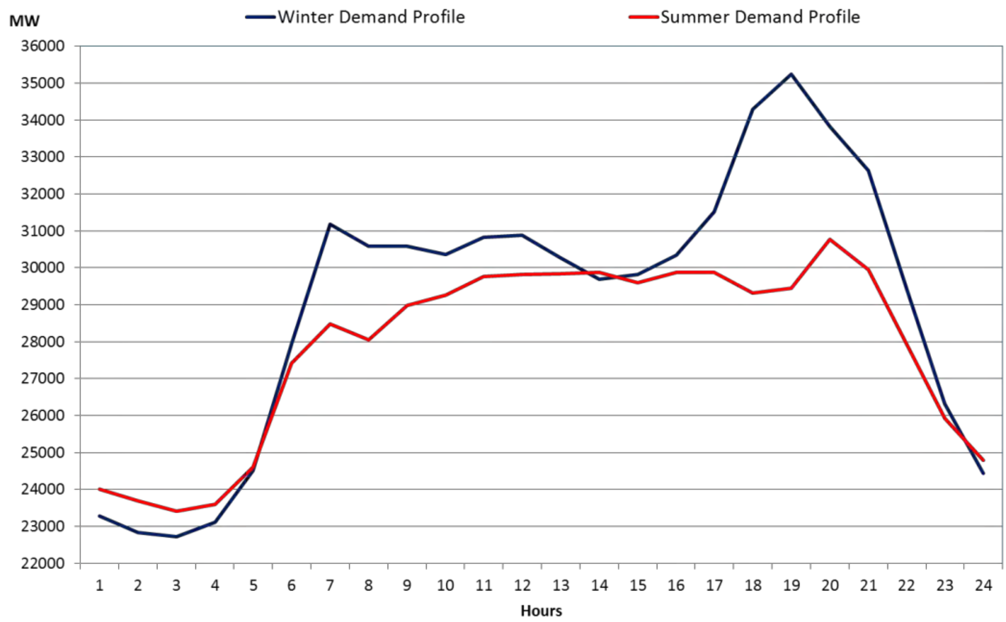


***Figure 5.1: Load Profile for winter and summer period***

### 5.1.1 Winter Constraint

The winter profile is very peaky in the evening. During the winter period the constraint would be mostly during the evening peak and occasionally during the morning peak. The constraint in winter is a demand constraint. This requires the use of peaking reserves more. The duration for evening peak is mostly 2 – 3 hours. On any particular day if the system is constrained and the use of emergency reserves is necessary it would be for approximately 2- 3 hours.

### 5.1.2 Summer Constraint

The summer profile is flat. During the summer period if the system is constrained it is for most of the day; also bearing in mind that in summer most generation plant is taken out of service for maintenance. During the summer period therefore if the system is constraint it would be for 8 - 10 hours.

Dependent on the conditions or shortfall on the day, this requires then the use of emergency reserves for almost the entire day. Also the peaking plant is needed for the whole day due to the flat profile; the difference in morning and evening peak is very small.

Now that the constraints for summer and winter have been discussed, let’s look at the emergency merit order.

## 5.2 The Emergency Merit Order

The current day ahead dispatch rules are to secure base load generation capacity to ensure the demand is met. The dispatch of these units is based on costs implying the cheaper units are dispatched first as a base load capacity but also with constraints in mind. Constraints are typically which units are contracted for AGC and other technical constraints on the units, for example temporary or seasonal limits on rated power or energy capacity. Day ahead dispatching also needs to cater for the various reserve categories and to ensure that enough reserves are available. Importing generation from neighbouring utilities can also be done as well as the scheduling of municipal generation. This calculation of this cost is not part of the scope of this dissertation but it should be done as it is very relevant to influencing the merit order.

The emergency reserve dispatch merit order is the order used to dispatch the emergency reserves. The emergency reserve dispatch merit order varies depending on system conditions and constraints. Currently the merit order is compiled based on resources available and an assumption on cost of dispatching OCGT’s. A process is followed in determining the use of the products in the merit order and it is related to capacity constraints of the power system. The day ahead risk for capacity constraints is calculated and based on this assessment DMP and hydro are scheduled. In some cases the emergency merit order will be overridden by the operator due to the dynamic nature of the power system and certain technical limitations or constraints.

It has become important to add the cost of dispatching the different resources to ensure that they are cost effectively dispatched and to quantify the cost associated with the different resources used.

The lack of a decision-making tool or process in dispatching the emergency reserves leaves the speculation that running the open cycle gas turbines or manually interrupting customers (load shedding) are too costly for the country. It also leaves the choice to the operator without equipping the operator with adequate tools to make a more informed and accurate decision.

In chapter 6 the focus will be on the cost calculation of the operating reserves.

## Chapter 6 – Aspects of the Short and Long term Cost Calculations

The cost calculations comprises of a short and a long term calculation. The long term cost calculation focuses on the cost to the company over a longer period (e.g. a year) whereas the short term cost calculation focuses on the real time operational running costs only. It should be noted that the merit order for these two areas will be very different.

The total cost per MWh, is the fixed cost plus the variable cost. The variable cost, includes the VOM cost whereas the fixed cost is a standard cost per year and it uncured whether the OCGTs are dispatched or not.

In the cost calculation chapter for the OCGTs two cost calculation methods as done by the generator and the second calculation is as done by the System Operator. This area will be expanded on more in the relevant chapter.

Another aspect is the cost of load shedding. The fixed cost incurred here is a standard value based on defined COUE as per the Deloitte. The cost of load shedding to Eskom, would be the cost of revenue lost. It is calculated based on loss of production to customer sections. The correct way would be to calculate the revenue loss to these customers and to use the tariff to calculate the actual cost to Eskom, this however is not part of the scope of this dissertation. For this particular comparison the cost to the country meaning loss of production using a standard cost for load shedding has been used. The cost of load shedding or running of OCGTs is not funded by the tariff. Future work needs to be done to give a complete view of all the relevant costs to company and country.

The cost calculation is to determine the merit order for dispatching emergency reserves namely OCGTs. DMP, ILS and load shedding are considered in this dissertation.

## Chapter 7 - Cost of Operating Reserves

Reserves have to be procured by the System Operator to ensure reliability and security of the power system. Prior to 2009 reserves cost in South Africa had a market focus and had a different costing methodology. The power pool market existed at that time and Eskom procured reserves in a different way. Since 2009 the reserve costing methodology changed and reserve costing is as per the costing methodology that follows in this chapter.

### 7.1 Cost of Instantaneous, 10 minute and regulating reserves

The current costing philosophy is silent on costs of operating reserves. It allocates a very small cost to these reserves and lacks depth of how these costs were calculated.

The cost of instantaneous and regulating reserve should at least be a significant amount to ensure generators are adequately compensated to deliver this very crucial service. The current performance for regulating and instantaneous reserves needs improvement. The lack of good performance could partially be due to insufficient compensation. This has a ripple effect; it leads to a lack of operating reserves which results in the use of more expensive emergency reserves. The costs of these are not comparable to the emergency reserves; in fact they are practically for free.

The current challenge unfortunately has led to emergency reserves being used daily. Operating reserve should be less expensive than emergency reserves as it gets used daily.

The cost of operating reserve does not change the rule based dispatch of emergency reserves. The two are separate even though the one has a dependency on the other one.

The current cost of operating reserves is very low and is a matter that needs to have a deeper review. The costs of emergency reserves are discussed in the next chapter.

# Chapter 8 - Cost of Emergency Reserves – Open Cycle Gas Turbines (OCGTs)

The cost calculation for the OCGTs have two components. One is the short term cost calculation that will only consider the running cost of the plant. The second calculation is the longer term calculation that will include the fixed cost of the OCGTs as well.

## 8.1 Load Factor of the open cycle gas turbines

The open cycle gas turbines are designed to run similarly to peaking plant and were originally aimed at a 6 % load factor. In the generation-constrained period the machines have been run close to base load factors. This leads to logistical problems as the fuel loading is a challenge.
The ramp rate of the machines is lower than that of the hydro plant; it takes between 20 – 35 minutes to reach full load. The ramp rate is important when it comes to the dispatching of the emergency reserves.

## 8.2 Conditions under which the open cycle gas turbines are run

The OCGTs are used under two specific conditions namely the Cape constraint and the capacity constraint.

### 8.2.1 The Cape Constraint

The Cape constraint is a type of regional constraint. In the Cape Town region there is limited amount of generation to supply the demand of up to 5000 MW (based on 2009 data). Base load generation in the Cape area is in the order of about 2000 MW of nuclear power. A pumped storage facility (Palmiet) supplies up to 400 MW and the OCGT capacity at Ankerlig is 1332 MW and at Gourikwa is 740 MW. Palmiet and the OCGTs are peaking plant and is only available to assist during the morning and evening peak. The remaining base load generation has to be supplied from the Gauteng area which is approximately 1000km from Cape Town.
In the event that one of the transmission lines in the corridor to the Cape is out of service, the amount of generation imported on these lines is limited by ratings of the series capacitors on the lines. This means the base load generation is less from the Gauteng area. This therefore leads to the running of the open cycle gas turbines situated in the Cape Town area.

### 8.2.2 The Capacity Constraint

The capacity constraint refers to when there is nationally insufficient generation to meet demand as described in section 3.4. This is the other constraint when the OCGT's would be used.

## 8.3 Cost calculation of running open cycle gas turbines as calculated by generation division

The OCGT cost calculation is dependent on a number of variables. The biggest cost contributing factor is the fuel used for the plant. The calculation of the fuel cost from the generators' point of view is different from the system operator's point of view and the differences will be discussed after the assessment of the cost by the system operator.

### 8.3.1 Fuel Cost for running OCGT's

The turbines in South Africa are run with diesel, which can be quite costly, and the fuel cost varies depending on the diesel price at a particular time. There is a project to explore the running of this plant with natural gas, but the project is still in its pilot phase and will take a few years before it can be concluded if it's a viable option.

The fuel cost calculation is based on a standard consumption of 320 litres of diesel per MWh of electrical energy output. Using an average diesel price for 2009 of R4.01/litre the variable fuel cost per MWh is R1283/MWh.

The **standard fixed operating cost** including depreciation is R10.42 million

The **fixed and total cost per MWh** are shown in Table 8.1 for various monthly load factors.

*Table 8.1: Fuel cost calculation with 1, 6, 13 and 60% load factor*

| Monthly Load Factor | % | 1 | 6 | 13 | 60 |
|---|---|---|---|---|---|
| **Running hours** | hr/month | 7.2 | 43.2 | 93.6 | 432 |
| **Standard fixed operating cost for two Gas turbines** | RM | 10.417 | 10.417 | 10.417 | 10.417 |
| **Installed capacity at Ankerlig + Gourikwa** | MW | 2072 | 2072 | 2072 | 2072 |
| **Fixed cost shared over energy generated** | R/MWh | 698.2652 | 116.3775 | 53.71271 | 11.63775 |
| | | | | | |
| **Standard fuel consumption** | l/MWh | 320 | 320 | 320 | 320 |
| **Fuel cost** | R/l | 4.01 | 4.01 | 4.01 | 4.01 |
| **Variable cost for fuel** | R/MWh | 1283.2 | 1283.2 | 1283.2 | 1283.2 |
| | | | | | |
| **Total cost of OCGT energy** | R/MWh | 1981.47 | 1399.58 | 1336.91 | 1294.84 |

### 8.3.2 Key Findings

**At 1% load factor and for 100MW**:

Energy payment = 100MW x 7.2h x 1981.47 R/MWh

= R 1426658,4

Note that this is as the current practise is to calculate the cost of the OCGTs from the generator perspective. It is not necessarily the correct way of calculating the cost. This dissertation has highlighted this gap and the process of solving this has started and is indicated as part of the operational changes due to the findings from this research.

The higher the load factor the higher fuel cost but the lower the cost of OCGT energy. It is noted that operating at a 60 % load factor would remove the capacity of OCGT's from emergency reserves.

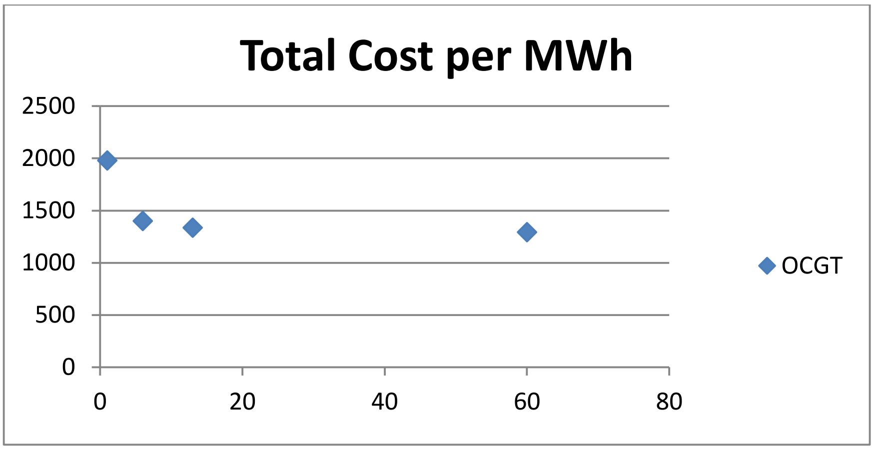


***Figure 8.1 Total Cost for OCGT***

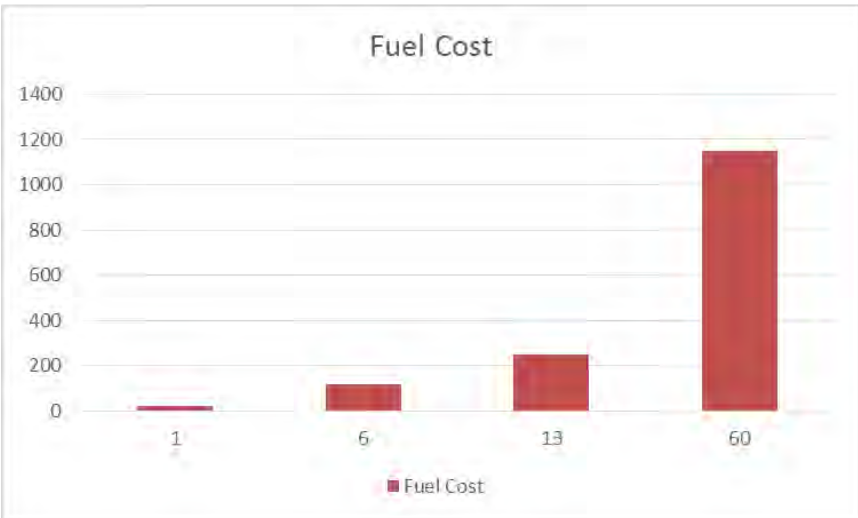


***Figure 8.2: Cost for 1, 6, 13 and 60% load factor***

## 8.4 The cost of call up of the OCGTs as calculated by the System Operator

Call up cost of the OCGTs consists of a standard fuel price, a variable operating and maintenance (VOM) cost and an energy payment. The System Operator uses a standard fuel price and a standard VOM cost for the running of this plant.

The running of these resources is seasonal and day dependent. The OCGT's cost on a weekday and weekend is exactly the same cost. The OCGT's have no schedule payment or penalty payment. The ramp up time is critical in terms of dispatch sequence. The operator's

decision is about the security of the power system or the cost to the business, each has its complications.
As per BPP (2009) for the allocation costing, the cost per MWh for the fixed and variable cost as calculated by the system operator is an allocation cost. The prices for fixed and variable costs are then defined as transfer pricing as per the literature review. The decision on where in the merit order it fits is based on the variable operation and maintenance cost and fuel costs only. Due to the difficulty of obtaining all the parameters, at best the system operator has to keep this in mind when deciding where in the merit order this resource fits in and a general approach is more useful, bearing in mind that the security of the power system is the mandate of the system operator.

### 8.4.1 Cost comparison for weekday and weekend for OCGTs

The weekend and weekday cost of running the OCGTs are the same depending on the fuel price.
Assume that:
the OCGT fuel price is R1460/MWh and the VOM cost is R266/MWh
the capacity scheduled is 100MW and the plant is run at 1 % load factor,
then the energy payment of running the OCGTs is given as
Energy Payment = (Capacity scheduled x hours required) (OCGT fuel Price+ OCGT VOM cost)
= (100MW x 7.2h) (1460 R/MWh +266 R/MWh)
= R 1242720

### 8.4.2 Analysis and Results

In 8.3.1, the generation context, the cost of energy for the open cycle gas turbines has been calculated using the fuel consumed. In this calculation the standard OCGT fuel and VOM costs per MWh have been used to calculate the energy payment. The generation calculation has a gap, the VOM cost is omitted. The challenge with using actual fuel consumption in the calculation is that the fuel price is not available at the time. It is better for the system operator to use the second method of calculation as the standard fuel price and VOM costs are available at any time. The second method gives a value less than the first calculation but the difference is small enough to be negligible on the bigger picture.
The gap is that as long as the system operator and generators use two different R/MWh values, the system operator cannot reflect true cost of the OCGTs to the system.

It is very clear from the calculation that the longer the machines are run the higher the total cost will be. This is in line with the assumption that the longer they are run, the more fuel is burned and the higher the cost including the VOM cost.

It would be interesting to explore the VOM cost and to see how it varies as the machines age and the maintenance cost increases. This will not be analysed in this dissertation due to the confidential nature of the information.

# Chapter 9 - Cost of Emergency reserves - Demand Market Participation Product

The Demand Market Participation Product refers to a type of demand reduction initiative. Customers in the industrial and commercial sector are contracted to reduce demand with payment. This consumer load can be reduced by dispatching from the National Control Centre based on the rules given in a commercial contract. No notice need be given in terms of existing contracts. This contract is a day ahead contract and has certain conditions.

## 9.1 Availability of the DMP resource

The DMP gets scheduled automatically if the day ahead operating reserves are below 1000 MW. Should the operating reserves be below 1000 MW it implies that the power system is constrained and that emergency reserves would be needed to meet evening peak demand.

The scheduling of this resource is only for 2 hours. It can be available within ten minutes after it has been dispatched. This product cannot be scheduled longer than two hours; if additional demand reduction is needed then Eskom needs to resort to the next available resource.

The gap with the scheduling is the availability of the 1000 MW operating reserves day ahead. If the operating reserves is less than 1000 MW day ahead, DMP is scheduled. If on the day there is not sufficient operating reserves and DMP is needed, but was not scheduled day ahead, penalties have to be paid for the use of it.

## 9.2 Cost associated with dispatching DMP

The product cost varies depending on whether it has been scheduled or if it is unscheduled. The weekend and weekday capacity payments costs are different for the day ahead scheduled DMP. There is a capacity charge payable if DMP is scheduled, even if it is not used. The charge for a weekday is 9.47 R/MWh and it is charged for the whole day, 24 hours. The charge for weekends is lower at 6.955 R/MWh. The capacity charge is for possible use any time during the day.

### 9.2.1 Daily Capacity Payment for scheduled day ahead weekday and weekends

If the capacity scheduled is 100 MW and the average capacity weekday price per MWh is 9.466 R/MWh then

Daily Capacity Payment = 100 x 9.466 x 24

= R 22718.88

For a weekend if the capacity scheduled is 100 MW and the average capacity price for the weekend is 6.955 R/MWh then

Daily Capacity Payment = 100 x 6.955 x 24

= R16692.48

**9.2.2 Daily Capacity Payment for unscheduled weekday or weekend day**

The capacity payment for unscheduled DMP has penalty payments of up to two days of payment additional to the normal capacity payment**.** The limitation with this is the customer is not obliged to respond and would need a notification period of at least 30 minutes.

For 100MW the daily capacity payment as per the calculation in 9.2.1 is R 22718.

Now if it is unscheduled for weekday:

Capacity Payment = 22718 x 3

= R68154

And if weekend:

= R16692 x 3

= R 50076

## 9.3 Energy payment for DMP

In addition to the capacity payment there is also an energy payment and it is not dependent on the amount of hours DMP was used. The energy price is 929.50 R/MWh. The energy payment is a standard fixed value. The energy payment is calculated using the following formula

Energy payment = energy price x capacity scheduled x 2 hours.

The DMP dispatched costs for weekdays are summarised in Table 9.3 below.

***Table 9.3 : Energy Payment calculation***

| | | scheduled for 2hrs |
|---|---|---|
| CAPACITY SCHEDULED | *MW* | 100 |
| AVG CAP PRICE WKDAY | *R/MWH* | 9.466 |
| DAILY CAP PAYMENT | *RAND* | R 22,718.88 |
| | | |
| ENERGY PRICE | *R/MWH* | 929.5 |
| **HOURS REQUIRED** | *HOURS* | 2 |
| **HOURS DMP USED** | | 2 |
| ENERGY PAYMENT | *RAND* | R 185,900.00 |
| PLUS OCGT PAYMENT | *RAND* | R 0.00 |
| TOTAL IF CALLUP DMP | *RAND* | **R 208,618.88** |

The weekdays and weekends energy payment is the same because the energy price is the same for a weekday and a weekend as well as for the unscheduled case.

## 9.4 Total DMP cost

The total DMP cost is the sum of the capacity payment plus the energy payment. For the scheduled case no penalty payment is incurred. If the product is used when it is not scheduled then a penalty is incurred. Total DMP cost for weekday, scheduled = Capacity Payment + Energy Payment = R208619 for 100 MW capacity.

### 9.4.1 Analysis and Results

DMP has two payments namely a capacity and an energy payment. The capacity payment is a standard payment for the entire day (24 hours) that must be paid whether the product is actually dispatched or not. The energy payment and the DMP total cost payment are the same for 30 minutes and 2 hours. Most of the customers' processes are sensitive and cannot be dispatched for periods less than 2 hours or for longer than 2 hours. It should be noted that if DMP is to be used for 3 hours, the last hour OCGTs will have to be run as DMP has a maximum time of 2 hours only.

The use of the capacity charge for DMP has shortcomings and advantages. The advantages are that it is more attractive to draw potential customers, the shortcoming is that money is spent without it actually being dispatched. Opportunities exist on how to make this tool more usable on the day if it was not contracted day ahead. The OCGT costs increase the longer the machines are run. This is not the case with the DMP, it has a limit of 2 hour use and it has a standard energy and capacity payment.

In the next chapter we will discuss the dispatching of ILS and load shedding.

# Chapter 10 - Dispatching of Demand Reduction Resources - Interruptible Loads (ILS) and Load Shedding

Interruptible load is consumer load that can be interrupted or demand reduced by remote control (or on verbal instruction) from the National Control Centre based on the rules given in a commercial contract. The scheduling of this resource is for a maximum of two hours per week and a recovery period of a minimum of 84 and 96 hours.

The interruptible load applies only to aluminium smelters and is implemented by shedding a 'potline', which is a unit of production. The sizes of these potlines vary and also the recovery period varies based on the size of the potline. It is important to be aware of the recovery time of these potlines as this is a limitation in the availability of this type of resource.

The ILS product is dispatched directly from the control room and can be dispatched any time with a 10 minute warning where possible. The cost of this product is very small compared to all the other resources. It has only one cost namely an energy payment. ILS can be dispatched from 5 minutes to 2 hours with the cost as per the use, whereas DMP payment is the same from 5 minutes to 2 hours. The cost to the customer, meaning production loss does not form part of this dissertation. It is a limitation as the availability and use of this product is directly influenced by this.

## 10.1 Cost Associated with dispatching ILS

The only cost to Eskom is the reduced tariff that is paid by the customer. The cost to the customer is the revenue loss associated with this special tariff during time of interruption of the customer. Cost to the customer is very relevant to future operation of this plant. In this calculation the cost to the customer is not considered, the focus is to determine the cost from a System Operator perspective to determine the merit order. Although the tariff is confidential an indication of the cost of dispatching ILS can be derived from the standard large user time of use (TOU) tariff for winter season for off peak ( June –August). It should also be noted that the change in merit order would need to be discussed before relevant changes can be made due to the confidential nature of this contract. The demand charge has not been calculated even though it should be part of the calculation because the ILS tariff is very low and it's only an energy payment. Let's assume the tariff is 12.16c \kWh

Cost for ILS for 100MW for 2 hours = 100 000 x2 x 12.16 c\kWh

= R24320

For 1 MW: is R243

No penalty payments are incurred, the cost is the same for weekdays, and weekends all year round. The constraint with this product is the availability and recovery period. This product is reserved to assure quick response to large contingencies is catered for.

## 10.2 Cost of load shedding

The current mandate of the utility is that load shedding is to be avoided at all costs. Load shedding is done as per the NRS 048 protocol. In this document the process and procedure to be followed for load shedding is clearly documented. The document is a NERSA regulation and has to be followed by all parties.

In the merit order this is reflected in that all other generation and demand reduction is scheduled before load shedding is called upon.

Load shedding is the same cost as unserved energy and can be calculated in the following way. If the demand to be reduced is 100MW and the duration for the reduction is 2 hours then:

Energy = 100 MW x 2 h

E = 200MWh

The cost of unserved energy price is R75/kWh [Deloitte, 2012]. This implies the cost for 100MW for 2 hours is

Cost = (200 000kWh x R75/kWh)

= R1 5000 000

Alternative calculation by using cost per customer sector:

For each sector in the economy the cost of unserved energy is different. According to the Deloitte report, the cost of unserved energy for 2012 is as shown in Table 5. The costs depend only on the energy not delivered, and are valued at a constant cost independent of the duration of an interruption.

Let’s assume 100MW is to be off for 2 hours and the contribution for the different sectors are as based on the sales figures in the Integrated Report [Eskom, 2010]. The redistributors and international utilities section has been subtracted and the remaining sectors expressed as percentage accordingly. The Eskom retail customer base only refers to traction so the transport contribution here is only from traction. Note that all these values are based on the Eskom retail customer base. The cost for manufacturing is the lowest in the Deloitte report [2012]; this seems to be inconsistent with reality. According to international benchmarking reports, manufacturing, or industrial as it is known is in most cases, the highest cost [Concept Economics, 2008].

Cost of load shedding = Unserved energy x cost of unserved energy

***Table 10.2 : Cost of unserved energy per sector values***

| Sectors | % contribution of Eskom's retail customer base | Sector COUE in R/kWh(2012) | Total COUE for 100MW for 2 hours |
|---|---|---|---|
| MANUFACTURING | 48.1 | 6.7 | 643200 |
| TRANSPORT | 2.6 | 111.9 | 581880 |
| AGRICULTURE/RURAL | 4.3 | 20.2 | 173720 |
| COMMERCE | 7.6 | 102.9 | 1564080 |
| MINING | 28.3 | 14.1 | 789600 |
| RESIDENTIAL | 9.1 | 26 | 473200 |
| | | Total COUE | 4225680 |

The second method cost is R4.2 million compared to the first method using the R75 per kWh value of R 15million. The second method calculation is very low compared to the 75 R/kWh, which highlights the fact that the cost of unserved energy for manufacturing is way too low. The nominal cost of 75 R/kWh will be used for this analysis as it is more reflective of the real cost of unserved energy. In chapter 11 the cost comparison for the different options is done.

# Chapter 11 - Cost Comparison for dispatching OCGTs, DMP, ILS and load shedding

Costs for the different resources are discussed in this chapter. In this assessment the costs evaluated was specific to the running of the plant and the fixed cost. The cost to the customer or the country is not considered in this calculation. In this assessment the costs relevant to the calculation can be categorised in 4 groups namely: lost sales revenue to Eskom or distributors during interruptions, second category is additional costs to generation, the third category is Capacity payment to allow interruptions and the fourth category is additional production losses.

***Table 11.1 Summary of cost categories relevant for emergency reserves***

| Option | Lost sales/Revenue | Additional generation Costs | Capacity Payment Costs | Additional production loss and costs |
|---|---|---|---|---|
| **OCGTs** | Not applicable | Have been considered | Not applicable | Not Applicable |
| **DMP** | Have not been considered – outside scope | Not applicable | Have been considered | Have not been considered – outside scope |
| **ILS** | Have not been considered – outside scope | Not applicable | Not applicable | Have not been considered – outside scope |
| **Load shedding** | Have been considered | Not applicable | Not applicable | Have not been considered – outside scope |

## 11.1 Fixed and variable costs for OCGTs, DMP, ILS and load shedding

The cost comparison table for the OCGT's, DMP, ILS and load shedding is shown below.

*Table 11.2: Cost for OCGT, DMP,ILS and load shedding for 100 MW capacity*

| For 1% load factor for OCGTs | | | | | | | |
|---|---|---|---|---|---|---|---|
| **OCGT** | | | | | | | |
| **Hours run per day** | **h** | Duration of operation | 0.5 | 1 | 2 | 4 | 8 |
| **Energy at 1% load factor** | **MWh** | | 14,918.40 | 14,918.40 | 14,918.40 | 14,918.40 | 14,918.40 |
| **Fixed cost Calculation** | | | | | | | |
| **Fixed Operating Cost** | **R** | Fixed cost for plant | 10,416,667.00 | 10,416,667.00 | 10,416,667.00 | 10,416,667.00 | 10,416,667.00 |
| **Fixed Operating Cost per MWh** | **R/MWh** | | 698.24 | 698.24 | 698.24 | 698.24 | 698.24 |
| **Variable Cost Calculation** | | | | | | | |
| **Variable Fuel Cost** | | | | | | | |
| **Standard Consumption (l/MWh)** | **l/MWh** | Litres consumed | 320 | 320 | 320 | | |
| **Cost per litre** | **R** | Price of Diesel | 4.01 | 4.01 | 4.01 | 4.01 | 4.01 |
| **Litres Consumed** | **l** | Amount of fuel Consumed for specific duration | 2,386,944.00 | 4,773,888.00 | 9,547,776.00 | 19,095,552.00 | 38,191,104.00 |
| **Total Fuel Cost** | **R** | | 9,571,645.44 | 19,143,290.88 | 38,286,581.76 | 76,573,163.52 | 153,146,327.04 |
| **Variable Operation and Maintenance Cost** | | | | | | | |
| **Price of VOM** | **R/MWh** | Cost of operation and maintenace as machines run | **266** | **266** | **266** | **266** | **266** |
| **VOM Cost** | **R/MWh** | | 1,984,147.20 | 3,968,294.40 | 7,936,588.80 | 15,873,177.60 | 31,746,355.20 |
| **Total Cost** | | | | | | | |
| **Total Variable Cost** | **R** | Variable Cost | 11,555,792.64 | 23,111,585.28 | 46,223,170.56 | 92,446,341.12 | 184,892,682.24 |
| **Total Variable Cost per MWh** | **R/MWh** | | 774.60 | 1,549.20 | 3,098.40 | 6,196.80 | 12,393.60 |
| **Total Cost per MW** | **R/MW** | | 736.42 | 2,247.44 | 7,593.29 | 27,580.17 | 104,734.74 |
| **For 100MW** | **R** | | 73,642.15 | 224,744.29 | 759,328.58 | 2,758,017.16 | 10,473,474.33 |
| **Total Cost per MWh** | **R/MWh** | Fixed Cost plus Variable cost | 1,472.84 | 2,247.44 | 3,796.64 | 6,895.04 | 13,091.84 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **DMP** | | | | | | | |
| **Day Ahead Scheduled for 100MW** | | | | | | | |
| **Fixed Cost = Capacity Payment** | | | | | | | |
| **Hours run per day** | **h** | Duration of operation | 0.5 | 1 | 2 | 4 | 8 |
| Capacity | **MW** | | 100 | 100 | 100 | 100 | 100 |
| **Capacity Price** | **R/MWh** | Price for capacity available | 9.47 | 9.47 | 9.47 | 9.47 | 9.47 |
| **Fixed Daily Capacity Payment** | **R** | Capacity Payment - for availability of DMP | 22728 | 22728 | 22728 | 22728 | 22728 |
| **Variable Cost** | | | | | | | |
| **Energy Price** | **R/MWh** | Price for energy used | 929.5 | 929.5 | 929.5 | 929.5 | 929.5 |
| **Energy Payment** | **R** | Cost for Energy | 185,900.00 | 185,900.00 | 185,900.00 | 185,900.00 | 185,900.00 |
| **Total Cost** | | | | | | | |
| **Total Cost for DMP (100MW)** | **R/MWh** | Fixed Cost plus Variable Cost | 208,628.00 | 208,628.00 | 208,628.00 | 208,628.00 | 208,628.00 |
| **Total Cost per MWh** | **R** | Total cost per MWh | 2086.28 | 2086.28 | 2086.28 | 2086.28 | 2086.28 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **ILS** | | | | | | | |
| **Hours run per day** | **h** | Duration of operation | 0.5 | 1 | 2 | 4 | 8 |
| **Cost** | **c/kWh** | | 12.16 | 12.16 | 12.16 | 12.16 | 12.16 |
| **Fixed Total Cost per MWh** | **R/MWh** | This is only a fixed cost | 240 | 240 | 240 | 240 | 240 |
| **Fixed Cost for 100MW** | **R** | | 24,000.00 | 24,000.00 | 24,000.00 | 24,000.00 | 24,000.00 |
| **Variable Cost** | | | | | | | |
| **Variable Cost** | **R/MWh** | Cost per energy is a fixed cost | Not relevant | Not relevant | Not relevant | Not relevant | Not relevant |
| **Total Cost per MWh** | **R/MWh** | Total Cost - Fixed Cost plus variable cost | 240 | 240 | 240 | 240 | 240 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Load Shedding** | | | | | | | |
| **Hours used per day (duration)** | **h** | Duration of load shedding | **0.5** | **1** | **2** | **4** | **8** |
| **Fixed Cost** | **R/MWh** | Is not considered in this calculation | N/A | N/A | N/A | N/A | N/A |
| **Demand** | **MW** | Amount of energy | 100 | 100 | 100 | 100 | 100 |
| **Cost of Unserved Energy** | **R/kWh** | Price of unserved energy | 75 | 75 | 75 | 75 | 75 |
| **Total Variable Cost for 100 MW** | **R/MWh** | Variable cost for energy for duration | 3,750,000.00 | 7,500,000.00 | 15,000,000.00 | 30,000,000.00 | 60,000,000.00 |
| **Total Variable Cost per MWh** | **R** | | 37,500.00 | 75,000.00 | 150,000.00 | 300,000.00 | 600,000.00 |
| **Total Cost per MWh** | **R** | | 3,750,000.00 | 7,500,000.00 | 15,000,000.00 | 30,000,000.00 | 60,000,000.00 |

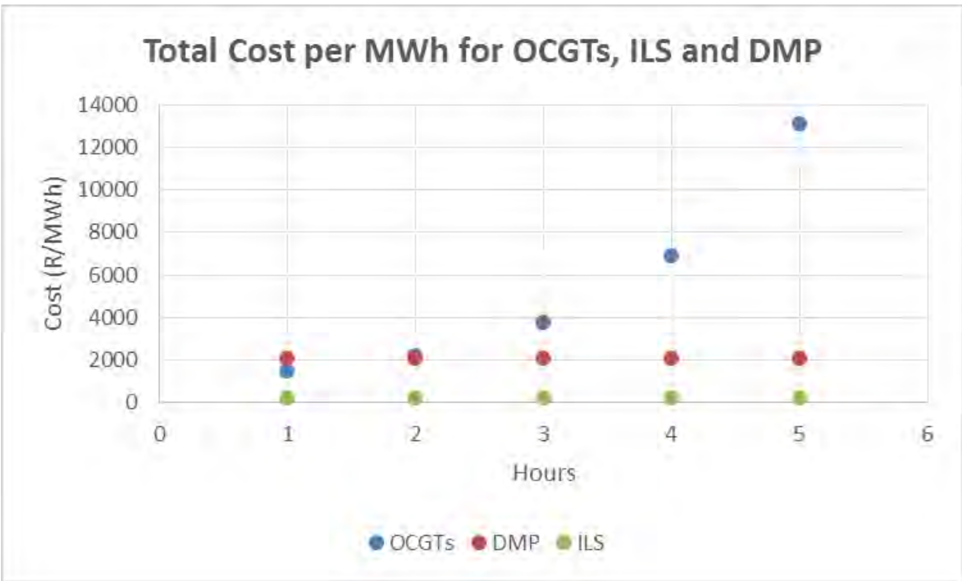


*Figure 11.1 : Cost per MWh for OCGT's, DMP, ILS*

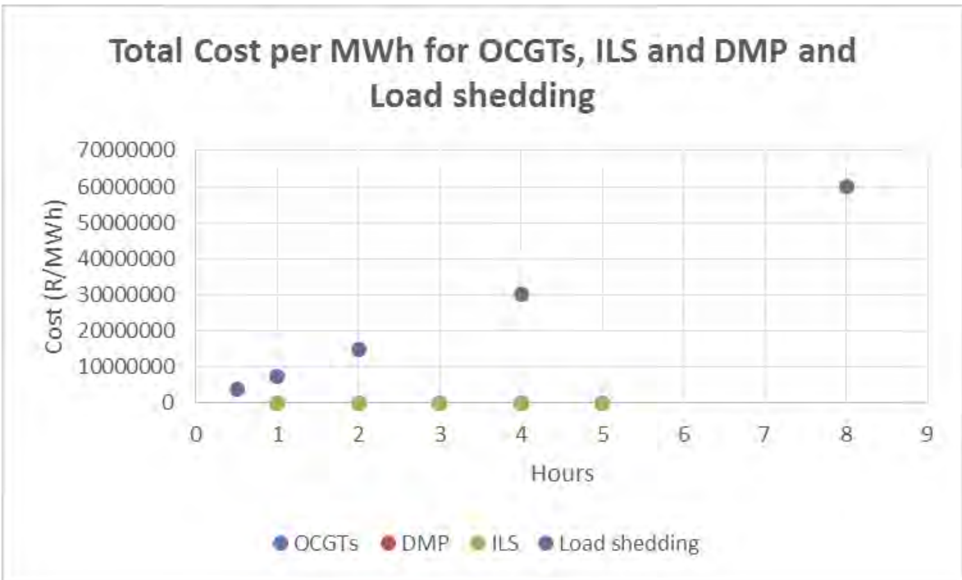


*Figure 11.2 Cost per MWh for OCGTs, DMP, ILS and load shedding*

The cost per MWh is illustrated in Fig 11.1 and 11.2. This is total cost per MWh, means it includes the fixed costs as well. It can also be seen as the long term cost to the company. The costs excludes the production loss to the owners of the industries e.g. Smelter interruption. DMP cost is a constant value and does not change with duration. This option is more costly at lower periods e.g less than 2 hours, because the cost is the same for longer than 2 hours.

The ILS cost is the cheaper but has the limitation of the contract only being available for 2 hours in the week.

The OCGT cost increases with the duration but for less than 2 hours it is cheaper to dispatch the OCGTs compared to DMP.

The cost of load shedding increases as the duration increases. Over the longer term period it means that load shedding would be a very high cost to the company, both from a revenue loss as well as economical loss to the country. When making trade-offs between shedding load or running OCGTs it should be noted that the OCGT cost is high but compared to load shedding it is a cheaper option.

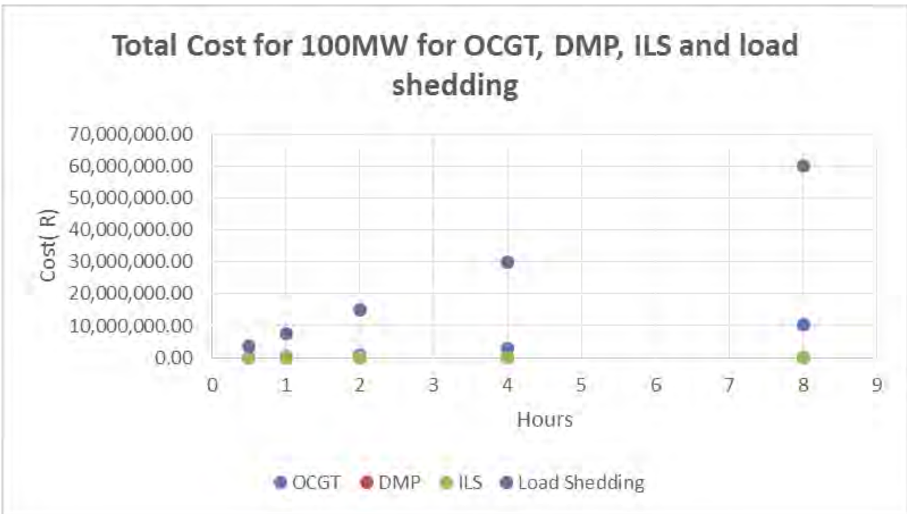


***Figure 11.3 Cost for 100MW for OCGT, DMP, ILS and load shedding***


***Fig.11.4: Cost comparison for 100MW of DMP, OCGT and ILS (scheduled for weekday)***

The same can be seen for the 100MW graph. The cost of OCGTs are less than DMP for less than 2 hours. Load shedding is still the highest cost option.

**Variable cost Comparison (short term)**

The variable cost only considers the cost while the plant is running. The DMP capacity payment has been excluded in this calculation.

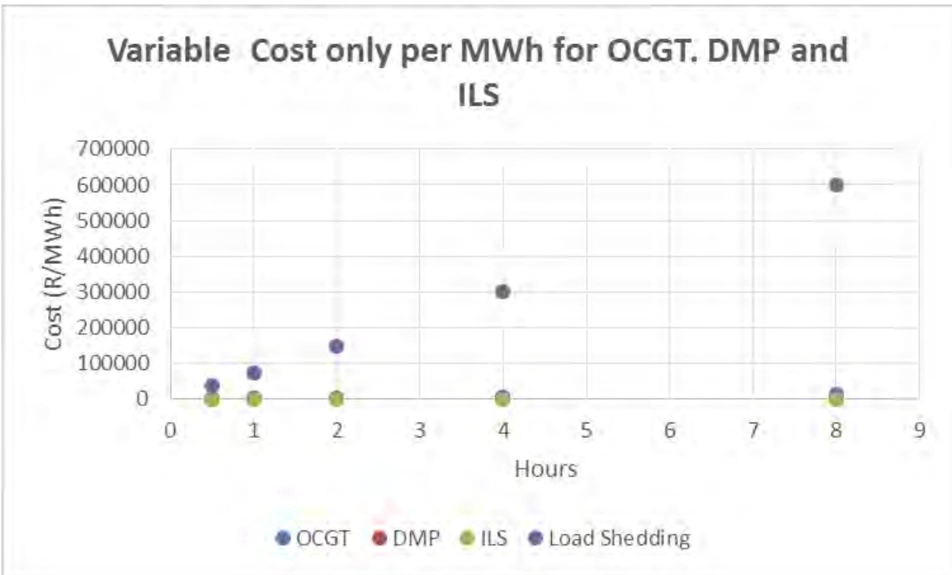


*Figure 11.5 Variable Cost per MWh for OCGT, DMP,ILS and load shedding*

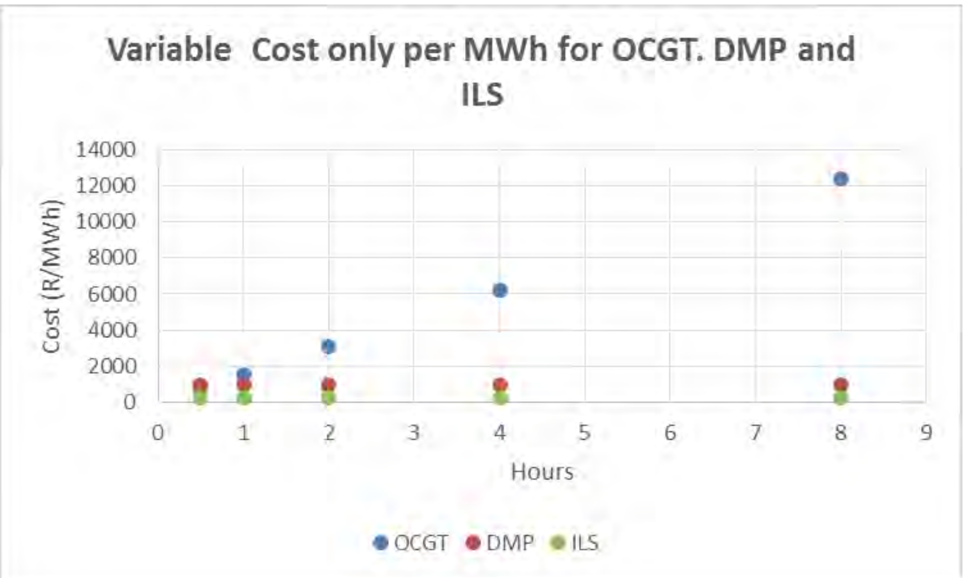


*Figure 11.6 Variable Cost per MWh for OCGT, DMP and ILS*

From figure 11.5 and 11.6 it can be seen that DMP is cheaper than OCGTs for less than 2 hours, if no capacity payment is included.

The ILS cost is the same as the total cost when both fixed and variable components are considered

The load shedding is still the highest cost option.

From this it is noted that the fixed cost can influence the merit order. In the option where the fixed cost is included DMP has a higher cost in the less than 2 hours period and in the variable cost only consideration the DMP product is cheaper than OCGTs for less than 2 hours.

The philosophy of the merit order will be an important consideration to determine whether the short term or longer term approach will be taken.

**Technical Constraints on using the emergency reserves namely OCGTs, DMP, ILS and Load shedding**

There are capacity available constraints on all the emergency reserves. The OCGTs have a maximum of 2.2 GW, the DMP a maximum as per contract (this can vary) and the ILS a max of 2159 MW.

These resources also have duration and recovery time limits. The ILS has a maximum of 2 hours use per week; the DMP has a 2 hour per event usage limitation.

The OCGTs have a ramp limit constraint, it takes 30 minutes before it can deliver full load.

In the event of a capacity constraint, from and economic analysis perspective, the ILS would be dispatched first; DMP would be dispatched if only variable cost is considered but if total cost is considered OCGTs are cheaper to dispatch if it is less than 2 hours. The OCGTs then follows the DMP and load shedding is the last in the merit order.

This however is not always the case, ILS is used to deal with severe contingencies like multiple unit trips or the complete loss of HCB (Cahora Bassa). The dispatch order is then first DMP, then OCGT's, then ILS and finally load shedding if all resources have been used.

For capacity constraints less than 2 hours, DMP and ILS are less costly to run. The problem with the less than 2 hour capacity constraint is the OCGT ramp up time (takes 30 minutes to start up)

For constraints that are 2 hours long, DMP and OCGT can both be used, DMP should be preferred as it is slightly cheaper, if only variable cost is considered and has no ramp rate constraints.

ILS is the cheapest and can be used any time but the constraint is the amount of hours this product is available. It needs a recovery time, so it should be well planned when to use it.

To simplify this to a rule based approach that operators can use in decision making on dispatch; the following should be used to determine the merit order for dispatching the reserves:

1. The duration of the event.
2. The size of the demand gap
3. Resource capacities available
   3.1 DMP
   3.2 ILS
   3.3 OCGT
   3.4 Other
   3.5 Load Shedding
4. Constraints on resources available
   4.1 Dam levels
   4.2 Fuel levels
   4.3 Recovery time of potlines (MW available to use)
   4.4 Ramp rates

5 Risks exist on the system for which extra capacities must be retained

The rules would consider the duration of the event and the various constraints for ramp rates, and environmental legislative aspects. In addition logistical constraints have to be considered as well. Below is a depiction for the different options in increasing order of variable costs. It can be seen that if the variable costs is the determining factor of how options should be dispatched that the technical constraints could impact a particular option. The non-dispatch able emergency reserves has not been part of this dissertation and is not part of the cost calculation. Additional work needs to be done to determine costs impact of these options.

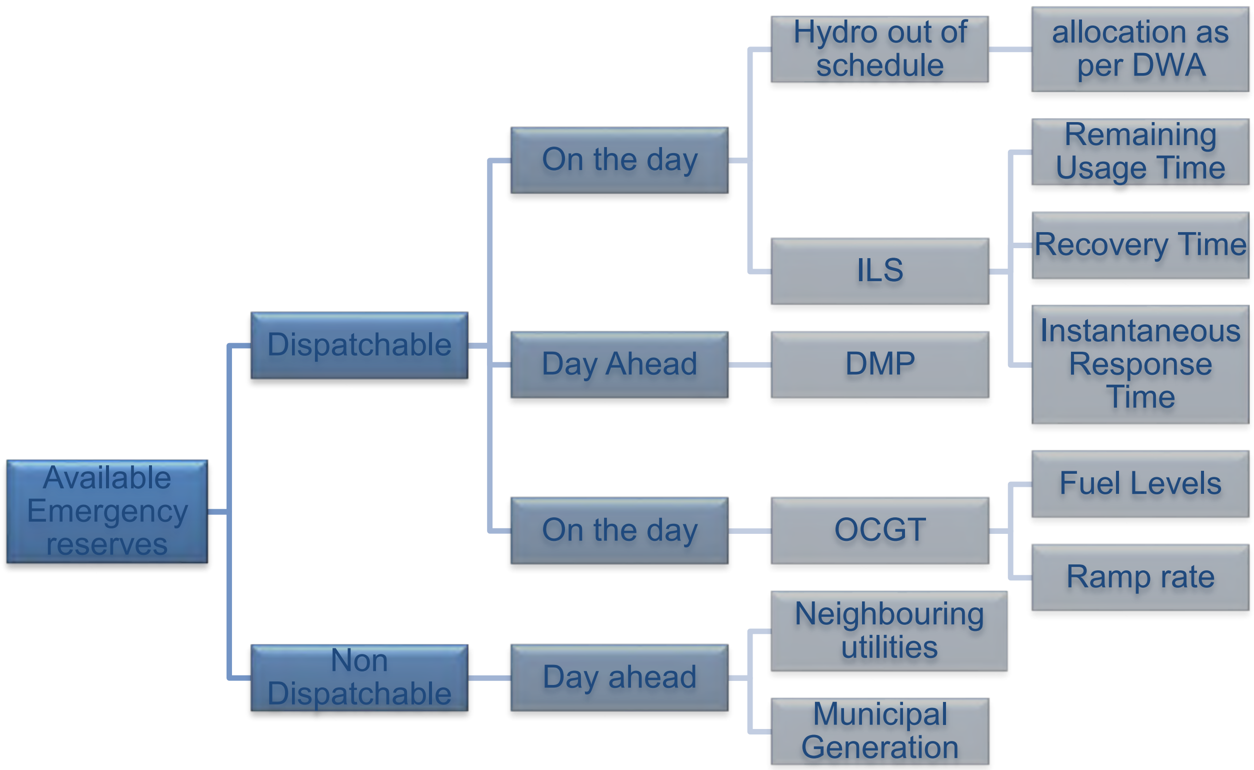


***Figure 11.7 Flow chart for Emergency reserves options based on Variable Cost Calculations***

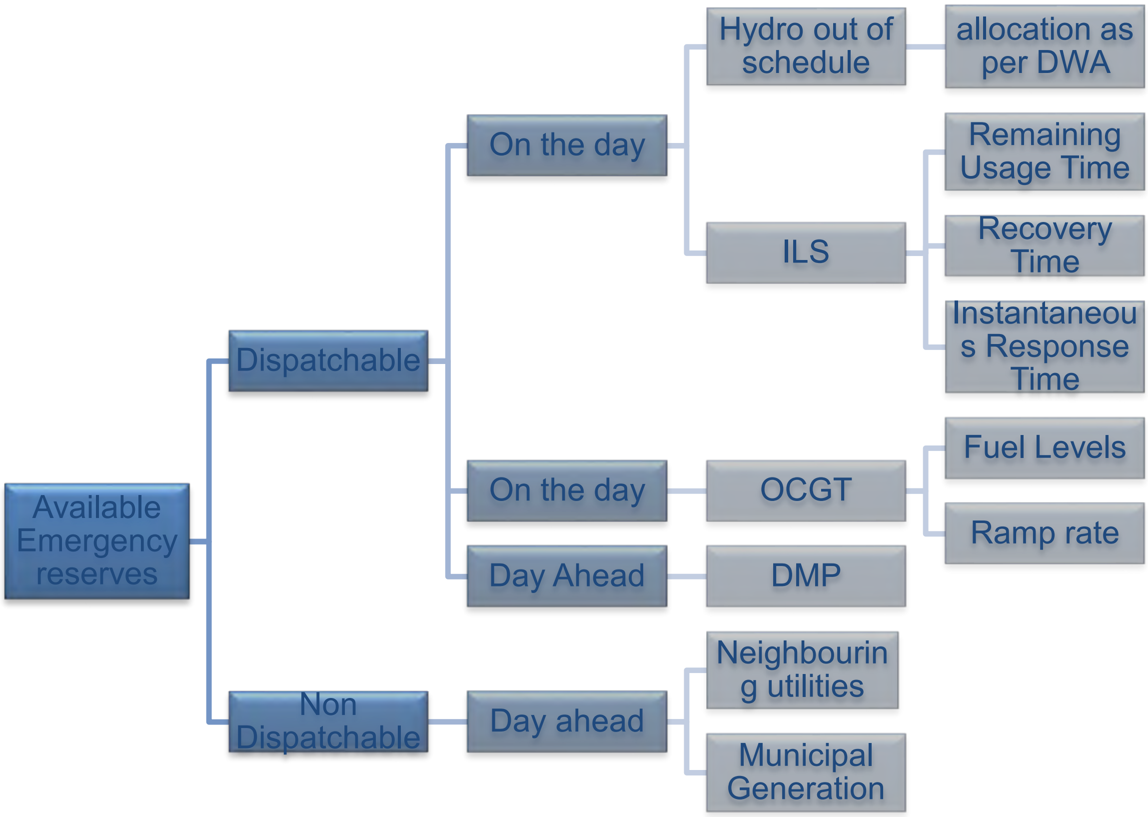


***Figure 11.8 Flow chart for merit order based on Total Cost***

For the period less than 2 hours, the total cost is showing the OCGTs are cheaper than the DMP to run. For longer than 2 hours the same order as per the variable cost applies.

# Chapter 12 –Discussion

## 12.1 Summary of the answers to the research questions

In chapter 1 some questions were posed that would guide the evaluation of the validity of the hypothesis that a decision on the dispatch of expensive emergency resources, like an open cycle gas turbine (OCGT), can be reduced to a rule-based process consistent with the needs of system operators. An extensive literature review and analysis of the data available from Eskom allow the hypothesis to be considered. The finding in respect of each of the questions is summarised below.

### Defining reserves for the system operator

The literature review shows standard definitions for reserves are different for all utilities. It is very difficult to have one standard definition as each utility differs in generation mix. The generation mix can influence the reserve classification. A main theme is the non-contingent, such as AGC, and contingent reserves. Most utilities have reserves that arrest frequency decay and then restore it. It can therefore be concluded that the reserve classification is utility specific.

### What is emergency reserves?

Emergency reserves are only mentioned for China and South Africa. The Chinese definition for emergency reserves is similar to a secondary response. The rest of the utilities have a similar concept, but it is called replacement reserves by some utilities.

### What factors affect the reserve dispatch decision?

There are various factors affecting the dispatching of reserves: contingencies on the grid, ramp time of units, constraints on available reserve resources and cost. The factors differ per utility due to the various definitions and classifications of reserves.

### Alternative resources to be considered in the dispatch decision

Alternatives to be considered in the reserve dispatch decision are also based on the availability of a resource. In some utilities cost plays a role; in South Africa it plays a role to a lesser extent. Mainly the constraints on the power system, for summer and winter as discussed in the constraint chapter, drive this decision.

### Period of operation to be considered related to the decision made

The period of operation plays a role in the decisions that are made. Mostly the use of resources is discussed for day ahead and on the day operation. The different timeframes means different variables are important in that timeframe. The real time (on the day) and day ahead timeframes have different assumptions and planning criteria. Typically the changes from day ahead to on the day is the amount of generation capacity available and this is related to machines tripping or machines not being able to perform as per the bid day ahead.

### Cost of risk and dispatch comparison

The costs and risks are discussed separately. The risks associated are system security and reliability. In the case where reserves are procured via a market, it's obvious the costs for procuring reserves are carried by the System Operator. This is the case for all the utilities researched. South Africa does not have a market system; there are costs for procuring reserves and it has some gaps in terms of the cost structure (some costs are very low). This is currently being reviewed.

### Cost sharing between stakeholders

In a market operated system the costs are legally binding in the buying and selling contracts. Different market participants share the cost with the system operator. In the South African context the costs are shared by the relevant stakeholders which are mostly internal.

### Indications of actual or impending constraint violations

Constraint violations refer to when a power system has limits defined that need to be kept intact at all times. Impending constraint violations are indicated by the alarms indicating the limit is almost reached. In the case of a capacity shortfall, the unavailability of operating reserves is an indication of a capacity constraint violation.

### Different rules for different resources

The rules change for different resources, based on the technical and, in some cases, cost constraints of the resource. In the market system the bids will guide in terms of rules for other generation types. A power system with many renewables, specifically wind, will have to carry extra reserves due to the intermittent nature of the generation. In some cases, like with solar and wind power, even weather has to be considered as a reason for change in rules.

### The result and an optimum solution

The result of the research shows an optimum solution differs per utility. In South Africa a rule base process can be identified but the solution would not be applicable generally to utilities even similar utilities.

The rules would consider the duration of the event and the various constraints for ramp rates, and environmental legislative aspects. In addition logistical constraints have to be considered as well. Below is a depiction for the different options in increasing order of variable costs. It can be seen that if the variable costs are the determining factor of how options should be dispatched that the technical constraints could impact a particular option. The non-dispatchable emergency reserves have not been part of this dissertation and are not part of the cost calculation. Additional work needs to be done to determine costs impact of these options.

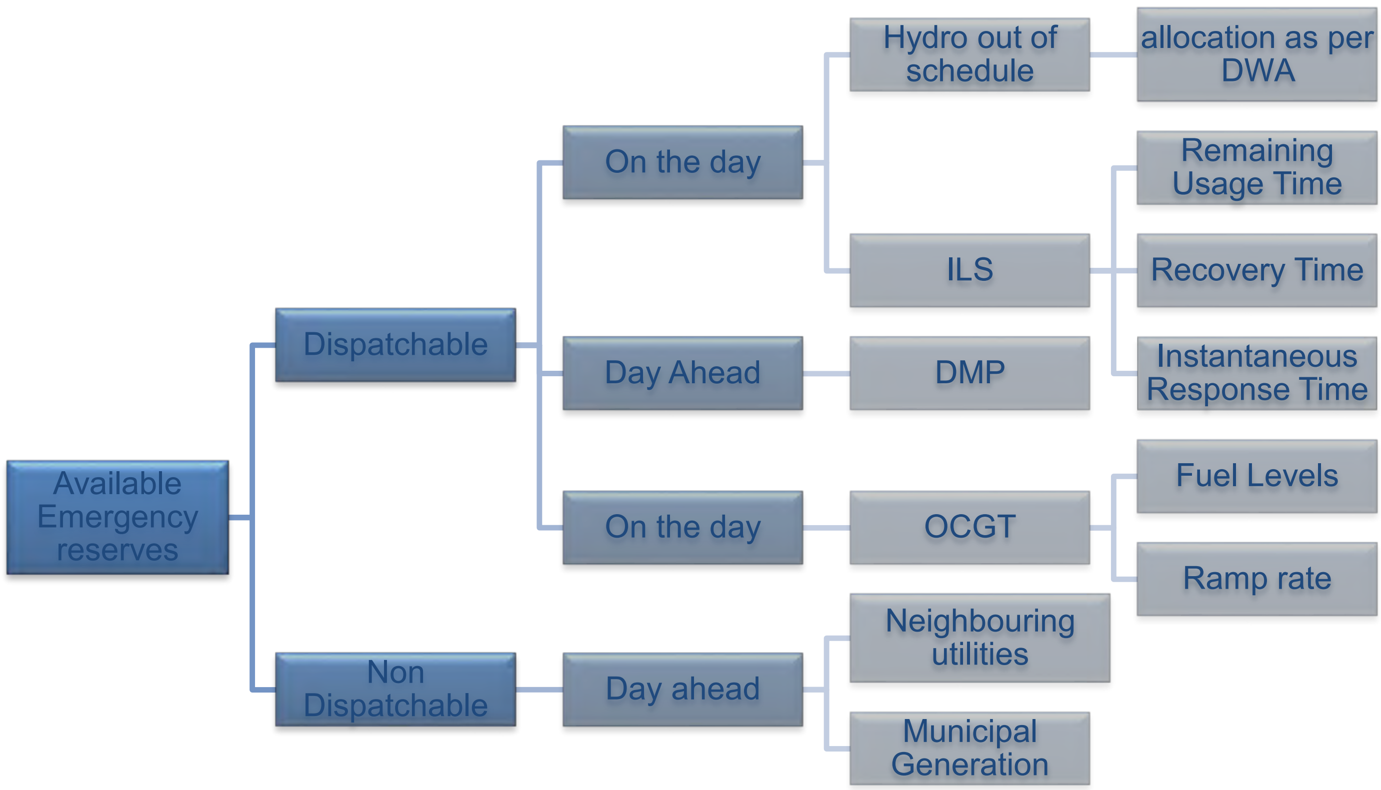


***Figure 12.1 Flow Chart based on Variable Cost***

The second option presented here takes the total cost of the options in consideration and the dispatch-able options are ordered in increasing order of cost.

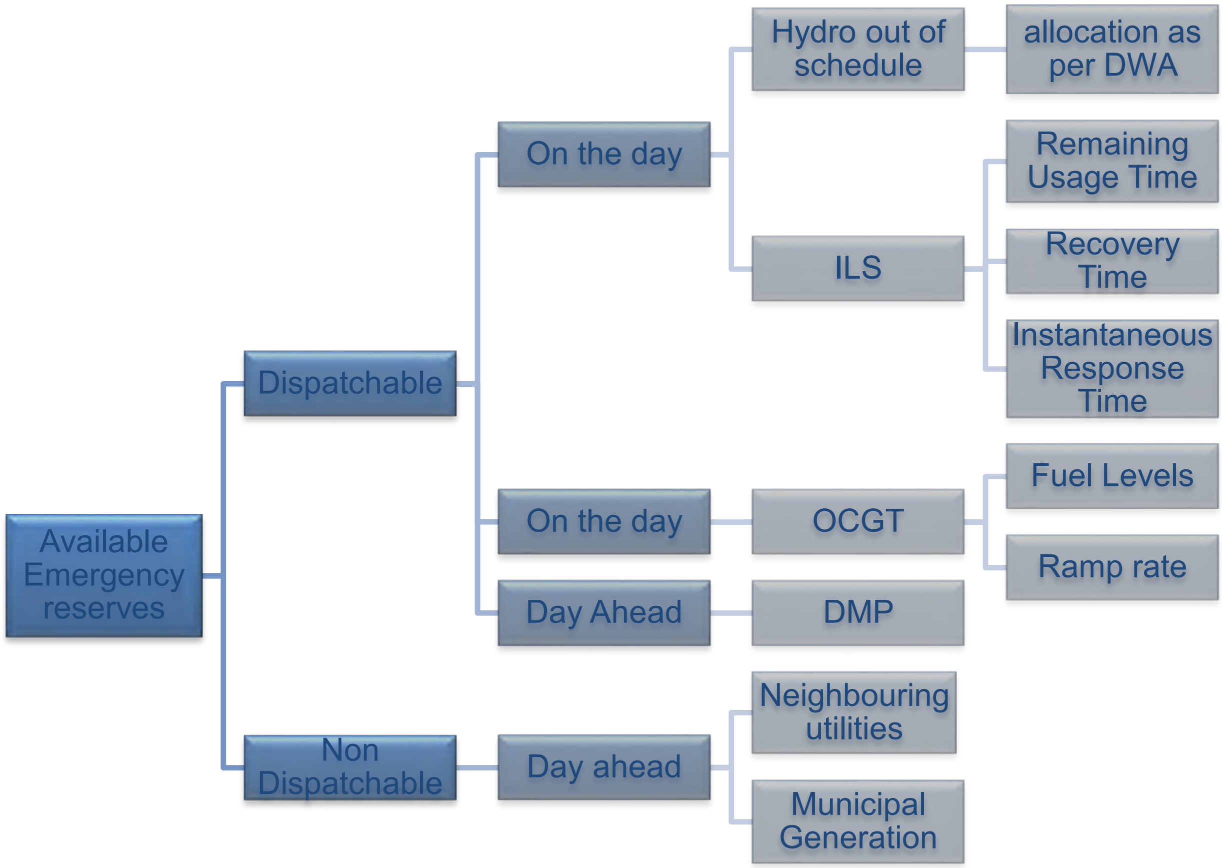


***Figure 12.2 Flow Chart based on Total Cost***

For the period less than 2 hours, the total cost is showing the OCGTs are cheaper than the DMP to run. For longer than 2 hours the same order as per the variable cost applies.

## Chapter 13 – Conclusion

The hypothesis was that a decision on the dispatch of expensive emergency resources, like an open cycle gas turbine (OCGT), can be reduced to a rule-based process consistent with the needs of system operators. The research finds that a rule-based approach might be feasible, but that there are discrepancies and discontinuities in the existing costing systems for a coherent approach to be formulated. It is also highlighting that a pure cost approach is not feasible as there are other technical consideration that needs to be taken into account when making the decision.

**Value added from the research**

This dissertation has shown using the OCGTs on AGC is too costly and should not be done at all. Operating philosophy has changed as a result of this; looking at the cost analysis in the previous chapter it was clear that it would be inefficient to do that.

The research has also added value in emergency operations e.g., during the period of the research, several instances of very constrained supply have arisen and the decisions on best ways of managing the conditions benefitted from the improved clarity brought to the operators' attention by this research.

Nersa has within the month of February 2015 authorised the running of the open cycle gas turbines at 30 % load factors. These changes will affect the transfer pricing and allocation costing and the tariff. The issues related to the dispatching of emergency reserves are dynamic and what the research has done is highlighted an internal Eskom process to deal with these matters. The usage and position in the merit order will need reviewing regularly as it is influenced by regulatory and other technical information.

Shrivastaka et.al [2014] has used a portion of this research in the paper on dynamic energy and reserve dispatch solutions

However, the work has not yet been completed, as the research has identified areas for change as the utility moves towards a more consistent approach to this aspect of system operation.

**Changes implemented to operations due to the research**

The definitions of reserves have been realigned as per the corrections identified in this dissertation. All the relevant tools the operator use to determine how much reserves are available in the various categories have been changed also to align with this. This has already been implemented in the control room.

Further to this due to the research and findings the system states have been reviewed and redefined to provide clarity.

On the day rescheduling is currently being developed as a result of the gap highlighted due to this dissertation.

The research has highlighted gaps in the current reserve categories to address the various contingencies that can occur on the power system. Work to improve on this has started and we are currently reviewing all the reserves to ensure we are aligned with the current operating conditions. This includes the payment to generators for reserves.

Forecasting the instantaneous demand has been identified as a gap, subsequent to that, an instantaneous forecast has been developed, and has been implemented and is a much better alignment to determine the shortfall between capacity and demand.

The dispatching of plant, base load generation, as well as emergency reserves is also being reviewed in light of what the research has shown. Optimisation taking the various aspects into account is being discussed. The optimal solution is not yet formalised. The research has shown the complexity of the problem and it also has identified the need for more in depth study in this area.

The robust discussions that were triggered while doing the research have deepened the understanding of concepts for the operators (in control room) as well as support staff.

Another fundamental shift and currently undergoing change is the load shedding aspect of it. The issues around how costly load shedding is to the country and the social impact are being reviewed. Various debates and views exist at present with the various stakeholders, internally and externally. External stakeholders e.g. the regulator, the different governmental ministries and industry are currently being challenged and explored with this research forming a platform and giving context to the discussions.

The question of whether the daily scheduling and rescheduling of peaking plant be done is also currently being reviewed. To optimally dispatch, the peaking and emergency reserve plant should be dispatched day ahead by the generation scheduler. These discussions are ongoing and improvement opportunities have been identified and will receive the necessary attention.

In chapter 10 it was found that the costs of customer interruptions, as defined by the present guidelines in the utility, appear to be inconsistent with practical expectations and internationally adopted figures, and these details should also be reviewed.

The research has been very useful and certain changes have already been implemented. There are existing gaps which have also been identified as improvement areas for the system operator. In the scope and limitations the areas excluded have been identified. This research needs to be extended to include those areas to form a holistic view of the cost aspects associated with the dispatching of emergency reserves in South African power networks.

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