The Development of a Composite Transmission Electrical Network Utilisation Comparative Study Index

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Declaration

I, the undersigned, hereby declare that the work contained in this dissertation is my own original work and has not been previously, in its entirety, submitted at any university for a degree. The sources that I have used or quoted have been to the best of my intent and knowledge, indicated and acknowledged by means of references.

Signature: Date:

Abstract

The aim of the proposed study was to develop an electrical utility organisational performance measure indicator that measures electrical network utilisation *(U)* for the actual maximum demand and total energy transferred. The scope of the study extended itself to include reliability and exogenous considerations. The scope of the research study included three primary variables with secondary variables as the performance measures.

The available data was screened and filtered from outliers, and thereafter, multivariate analysis was applied in deriving the overall linear equation for each of the above primary variables. The statistical process included the application of principal component analysis and factor analysis, a comparison between the two, and the derivation of linear equations. The study produced linear equations relating to the former.

The primary variables were presented in the form of a 3-Dimensional scatter plot. Each variable was inspected for linearity and clustering to validate the results and include any previously excluded outliers that complied with linear functionality. A practical application of the research findings was included. This included the extremes of linearity and clustering. The research concludes with further research opportunities in this study direction.

Samevatting

Die doel van hierdie ondersoek was om 'n maatstaf te ontwikkel wat elektrisiteitsverskaffers in staat stel om die effektiwiteit en benutting van die elektriese transmissienetwerk te meet. Dit sluit die maksimum aanvraag en totale hoeveelheid energie wat deur die transmissienetwerk oorgedra word in. Die omvang van die studie is uitgebrei om ook eksterne faktore en betroubaarheidsoorwegings in te sluit.

Die beskikbare inligting is gekeur en gefilter om uitskieters uit te skakel en daarna is multivariate analise gebruik om 'n lineêre vergelyking vir elk van die primêre veranderlikes te ontwikkel. Die statistiese analise het onder andere van hoofkomponente analise en faktor analise gebruik gemaak. 'n Vergelyking tussen die twee metodes is gemaak en liniêre vergelykings is afgelei.

Die primere veranderlikes was gesamelik getoon in n' 3-dimensionele grafik. Die lineariteit en groepering van elke veranderlike is egter ondersoek om die resultate te staaf en enige uitskieters wat voorheen uitgesluit is maar wel aan die lineêre verband voldoen het in te sluit. 'n Praktiese toepassing van die bevindings was uitgevoer en het die uiterstes van lineariteit en groepering ingesluit. Die ondersoek word afgesluit met 'n bespreking van moontlike verdere navorsingsgeleenthede.

Dedication

In loving memory of my daughter WENDY. Your absence has caused many an empty heart, but your smile will live far beyond your short nineteen years of life.

To my wife Elise, who has been my sole inspiration and example of commitment, loyalty, and self-achievement.

To these supporting values that guided me throughout.

- To *every opportunity afforded* to me, realising that many individuals, who if given the same, would be in a similar or better situation.
- To the *"Inner Spirit"* that provides the talent for creativity, endurance, and encouragement for achieving our expectations; and the ability to cope with the less humbled.
- To *true happiness*, a state when we have the ability to align our achievements with our expectations and at no emotional cost to our loved ones – *a lesson often learnt too late!*

Acknowledgements

I wish to record my sincere thanks and appreciation, in no specific order to:

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- My promoter, Professor Toit Mouton, for his continual encouragement during a lengthy and lonely journey.
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- Eskom for supporting and sponsoring the research project.
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Contents

Chapter 1

BACKGROUND INFORMATION

Chapter Objective

This chapter's objective is to provide a background to the new challenges facing electricity utilities specific to providing reliability and availability in the face of increasing competition, regulation and privatization. The concept of a "non-financial" balance sheet is introduced emphasing that the survival of any organization is not only dependant on financial indicators. The research methodology introduces the type of research, subjects of research, data collection source, data collection sample size and data collection variables. These are discussed in more detail in Chapter 3. Definitions and the motivation for these variables are included.

1.1 Overview

Increasing trends of international organisations to more effectively utilise depreciable and human resource assets can be attributed to intensified market competition, declining market shares due to globalisation, global transparency and general slowing down of economies. Reduction of military budgets have had an adverse affect on local and international manufacturing industries and the mining of these raw materials. However recent international awareness against continuing global terrorism, internationally opposed United States and coalition force invasion of Iraq, and the growing concerns over North Korean nuclear armament programme, will have an expected effect on the former.

The business environment has evolved from the traditional industry of heavy manufacturing to the current era of information technology and the transportation thereof via technologically sophisticated telecommunication systems. In addition to the above, most organisations are currently being confronted with achieving the three interlinked goals of economic prosperity, environmental protection and social responsibility.

Electricity utilities have themselves become the target of transformation with the prospects of privatisation and deregulation. These possibilities have reprioritised utility business decision making. The base for investment decisions have changed from a reliable income and growth of an industrial energy market sector, to a risk adverse domestic market sector with uncertain consumption growth. A further risk of local income and network utilisation is the approaching of certain mining industries to the end of their expected life. This will have the effect of shifting the demand for energy from currently constrained transmission networks. The increasing global pressure to recycle used materials has further reduced certain primary raw material mining requirements.

To date, organisations have carried out annual business evaluation by mainly financial means in the form of an income statement and balance sheet. Executives and managers have focused on optimising the former financial returns at times to the detriment of the organisation. Production assets are often prematurely sold, which although yielding favorable financial returns, presents additional risk on the technical sustainability of an organisation . A case in point is the South African Airways and the selling of airliners during the mid-nineties by CEO Coleman Andrews. Another example of the primary focus on final accounts was the overstatement of profits by $591 million over five years (1997 to 2000) by Enron Corporation during 2001. The intention was that this would increase the share value and attractiveness for potential investors. The seventh largest corporation in the United States took a precipitous dive, losing $60 billion in value within months and eventually realised financial ruin. Similarly the retrenchment and outsourcing of specialist skills places additional risk on the long-term operational sustainability of the utilisation of an electrical network. Retrenched specialist skills are often diluted to a more generalized engineering level or lost to totally new business ventures.

Other than financial analysis in monetary units, an electricity utility must consistently and regularly evaluate itself on the non-financial aspects of the business – a *non-financial balance sheet*. A dimension within the *non-financial balance sheet* is the measurement of production asset utilisation and the effective utilisation thereof. The utilisation reviews the operational functionality as a function of cost effectiveness and service level. From the electrical utility point of view major dimensions in “service level” are both the *continuity* and *quality* of the product – namely electricity.

Reliability of a transmission network is the extent to which consumers can obtain electricity from the network in the quantities and quality they demand. In order to provide electricity to consumers in a reliable manner, transmission must transmit electricity and ensure transmission line capacities are adequate to meet demand – all plant, equipment and processes must be compatible with the power supply. Furthermore they must also ensure that the proper operating and maintenance procedures are followed. Quality of supply is not only focused towards delivering a customer product, but also an international environmental requirement. Standard IEC 50 (161-01-07) defines Electromagnetic Compatibility (EMC) as “the ability of an equipment or system to function satisfactorily in its electromagnetic environment without introducing intolerable electromagnetic disturbances to anything in the environment.” Not only utilities, but also customers are obliged under IEC 61000-4-11 to have immunity levels higher than the compatibility levels specified for any given phenomenon, and disturbances from customer installations must be below system authorized emission limits so that their cumulative effects do not exceed compatibility levels. Internationally, to date less effort has been directed at benchmarking transmission quality of supply levels. This is mainly due to the relative proximity to the end-user and the events relating to transmission are included in distribution assessments. This has changed as large and influential customers are served from transmission levels, and the unbundling of vertically-integrated utilities into generation, transmission and distribution require that transmission performance be independently assessed.

The challenge of *more efficient utilisation* of plant and manpower skills can be realised by lowering operating and investment costs while reducing plant failure. Investment in electrical networks is associated with radical step costs without realising small incremental expansion costs. Reducing further investment costs can only be achieved by “stretching” the current utilisation of electrical network assets. Hence the casually used terminology of “sweating the assets” or “stretching the assets”. The challenge of a more effectively utilised transmission electrical network directs electrical utilities to benchmark themselves against other utilities and apply comparative study techniques. Accompanied with the challenge of *more effective utilisation* of the electrical network is the increasing customer demand for improved quality of electricity supply at an affordable price.

John Elkington has forecast that business in the 21st century will require focusing on three bottom line survival factors. Namely economic prosperity, environmental protection and social equity. The sustainability of business will depend on the prediction and transformation to changing markets, values, transparency, life-cycle technology, partnerships, time and corporate governance. These have a direct impact on the utilisation and future expansion of transmission electrical networks. The above is evident in the electrical utility industry. Locally Eskom is subject to transformation in all of these domains. Market changes include the cross border expansion into neighboring countries with the recent Mozal project posing additional supply demands and even expansion on the transmission network. In contrast future prospects of the utilisation of pebble-bed reactors and small sustaining generating units pose a threat to optimal transmission utilisation and expansion programmes. New domestic markets have been identified and electrification programmes are absorbing greater resources, both financially and skills based. Values within Eskom have changed both externally and internally. Externally Eskom is focusing on regional development (African Renaissance), “electricity for all” and social upliftment through educational and sport awareness programmes. As a parastatal utilisation serving the community at large, Eskom has to become increasingly transparent in the operations and investment decision-making within. Public demands this, as well as the National Electricity Regulator. However, competitiveness and transparency are often contradictory. To maintain a competitive edge requires the application and retaining of in-house strategies.

To comply with environment awareness policies Eskom must extend it’s decision-making to include the total life-cycle concept and technology. This includes from the conceptual design stage to the disposal of plant and equipment. Utilities are prioritizing asset management as a crucial survival strategy to sustain and improve technical performance. Transmission engineers are developing more skills in the primary function of asset management such as integrated planning, system management, asset planning, asset management and asset disposal. Engineers are focusing in particular on asset utilisation evaluation, network performance improvement studies, reviewing maintenance practices, estimating the remaining and extension possibilities of plant life and compiling action plans to achieve the former. Such action is intended to optimize and preserve the functionality of plant and equipment through employing engineering best practices aimed at avoiding, reducing and eliminating the onset of failures, against economic best practices. Furthermore such plans are to ensure optimal performance, availability and reliability during the normal and extended life span of the plant and equipment while ensuring minimal impact on the environment.

Energy-efficiency and conservation are crucial components of the debate concerning the direction of future energy policy. Measuring actual energy efficiency of any economy is a difficult task due to vast data requirements. The main two energy-intensity measures are: energy consumption per capita (tons equivalent of oil / capita), monetary unit of real gross domestic product per capita (GDP / capita). These energy-intensity measures can differ from measures of energy sources and efficiency.

There is an increasing need for Eskom to partner with neighboring utilities, generating sources, stakeholders and plant and equipment suppliers. Corporate governance has extended from an internal structure to an external source in the form of the National Electricity Regulator. All the above factors adversely affect electricity utilities in the decision-making process for network expansion and refurbishment programmes. The former strengthens the need to develop an appropriate comparative utilisation index for benchmarking utilities. Such an index can facilitate investment and operational decision making.

The booming technology-reliant American economy of the 1990's caused an increase in electricity demand. However, regulators kept consumer rates down, not permitting utilities to recover capital expansion in charged rates. Utilities were required to purchase power from other neighboring utilities resulting in a lack of need to inwardly focus on capital expansion. Between 1978 and 1992 reserve margins averaged between 25 – 30%, whereas following 1992 reserve margins have fallen to less than 15%. The former was in the presence of the North American Electric Reliability Council (NAERC) forecasting on annual growth in the national demand to be approximately 1.8% annually. In fact the growth has been between 2 – 3%.

From the historic and regional focus of transmission, the development of the role of transmission networks is now to transmit power across greater distances, at more competitive prices, and in more competitive markets. This is to be attained within the constraints of the previously mentioned survival factors of economic prosperity, environmental protection and social equity. During 1992 through to 1998 the subsidiary of Enron Development Corporation in India, the Dabhol Power Corporation (DPC) ignored or dismissed legitimate concerns for the local's livelihood and environment which serves as such an example. Enron Power was accused of corporate complicity in human rights violations. The engineering fraternity has always been confronted with the challenge of balancing the former. However, there is in modern times an increasing pressure to deal with increasing and diverse disciplines. Sole engineering focus has now expended to multi-disciplinary studies. Such is the focus of this study – *to include a multi-discipline scope of variables which will ultimately assist the transmission planning engineer in decision-making relating to electrical network expansion*.

1.2 Definition of the Research Problem and Research Question

1.2.1 Aim of the research.

The aim of the proposed study is to develop an electrical utility organisational performance measure indicator that measures overall electrical network utilisation. Utilisation must also be measured as a function of reliability (*R*) and external or exogenous (*E*) factors. This derived indicator must be suitable for international benchmarking of electrical utilities.

Traditional performance measures for both efficiency and effectiveness focus on either technical or financial aspects. They are not independent of each other and the need to ascertain the technical affordability of both network expansion and operational issues is of primary importance. Of increasing importance is matching the utility business (energy transfer capability) with customer requirements (peak energy demand). Customer demands have developed from the basic continuity of supply to demands on quality of supply (frequency and voltage regulation stability, stable voltage waveform, harmonics free supply, etc.).

The need to benchmark the world's best practices creates the need to develop a comparative measure to compare network utilisation. Results from current international comparative measures are difficult if not impossible to apply unilaterally. The main reason for this is that salient considerations that obscure the quantitative result are not taken into account. These include both endogenous (internal) and exogenous (external) considerations. Endogenous considerations include network configuration, distribution and location of supply and load points, inherent network risks, operational aspects such as maintenance and refurbishment policies, capital expansion plans, applied technology, and level of applied human resource capability. Exogenous considerations include economic development within a country, political influence in fiscal and monetary policies, and geographical and environmental factors.

The aim of this project is to derive an international comparative measure for electrical network utilisation that can be used by electric utilities to benchmark themselves. It is not intended to be a benchmarking exercise, but rather the development of the measuring tool to facilitate benchmarking exercises.

1.2.2 Objectives of the research.

The derived composite index must facilitate senior management of electricity utilities in making engineering management decisions regarding the operations of the transmission electrical network during the short and long run transportation of energy demands. By benchmarking their individual utility's transmission network utilisation, the respective utilities can ascertain their performance levels and project future utilisation targets. This is discussed in detail in s*ection 1.3 Motivation for the Research*.

The scope of the study will consist of researching three primary inputs or variables. These are discussed in detail in section *1.4.4 Data collection variables* and comprise of:

- *Utilisation variables (U).* These variables focus on the peak energy transfer capability of a transmission network.
- *Reliability variables (R).* These variables focus on the basic elements of the product "electricity" which measure its availability and reliability.
- *Exogenous variables (E).* The exogenous factors are external influences relating to economy, social and environmental considerations.

1.2.3 Research question.

1.2.3.1 Primary research question

How can a composite comparative study index for transmission electrical network utilisation be developed which is inclusive of the above primary comparative variables?

1.2.3.2 Secondary research question

What are the relationships between the various primary variables? That is, between U, E and R?

1.2.4 Previous and current research.

1.2.4.1 Existing comparison methods

There exists numerous benchmarking studies by utilities, consultants and research institutions. One of the most marked exercises is the "International Comparison of Transmission Performance" which was initiated and complied by National Grid Company plc. During the past 5 years twenty-four electrical utilities have participated. Eskom is one of the utilities which retained participation since the initial exercise. Other studies include the Edison Electrical Institute and the Grid study from Ontario Hydro. Included in these studies are performance indicators that measure financial, organisational and technical parameters. *Transmission assets utilisation* is measured by the ratio of transmission revenue over transmission assets. In broader terms, *asset utilisation* is measured by the ratio between revenue and capital employed.

1.2.4.2 Existing utilisation studies.

Recent local studies include the work of R Stephen and Riaan Smit of Distribution within Eskom. Their terminology refers to "capacity utilisation indicator" as opposed to "transmission electrical network utilisation index". The traditional methods of applying the ratio of transformer capacity to existing national peak have been revised due to the neglect of salient features such as firm supply points and the diversification of peak load areas.

The capacity utilisation index determines the power transfer capability of two primary components of the sub-transmission and distribution system; namely, substations and lines. The line transfer capability is dependant on design and operational constraints of voltage regulation, system stability and thermal limitations. The national lines utilisation is the (sum of the regional MVA-km)/sum of the regional maximum demands. The ratio between sub-transmission and distribution follows the Tepa Seppa model of 0.6 for sub-transmission + 0.4 for LV distribution.

The substation component is based on the transformer capacity utilisation and takes into consideration normal utilisation which is the rating as per transformer nameplate rating, and firm utilisation which is the utilisation of those transformers required to operate under contingencies of n-1. The utilisation of substations is determined by the present maximum loading of the substation / the total installed capacity. In the USA Tepa Seppa investigated the utilisation of sub-transmission systems and derived the following capacity/load ratios for both overhead lines and cables. *Table 2.1: Capacity/Load Ratios (Tepa Seppa)*.

Table 2.1: Capacity/Load Ratios (Tepa Seppa).

Year	Capacity (GW-km)	System Peak Load (GW)	Capacity/Load Ratio	
			Ratio (Miles)	**Ratio (Km)**
1974	*102,976*	*338*	*189.3*	*304.66*
1979	*125,502*	*397*	*196.5*	*316.13*
1984	*154,464*	*451*	*212.9*	*342.49*
1989	*167,336*	*495*	*210.1*	*338.05*
1994	*172,163*	*555*	*192.8*	*310.20*
1998	*186,644*	*648*	*179.0*	*288.03*

The above can possibly be linked to the recent electricity supply disorders experienced in California where transmission expansion was not timeously aligned with customer demand. An increasing number of GW-Miles capacity accompanied by a decrease in Capacity/Load ratio. The former is commonly used in transport economics for the transportation of passengers and raw materials.

1.3 Motivation for the Research

1.3.1 Overview.

Organisations have traditionally been evaluated for sustainability in monetary terms. This is by means of financial figures in their final accounts – namely income statement and balance sheet. There are increasing trends within large corporations to inflate the value of their assets. This then presents a favourable yet false financial evaluation. In some circumstances this practice has lead to the financial ruin of seemingly financially sustainable organisations. Focusing solely on financial sustainability has often resulted in the neglect of production assets. Asset management has witnessed contradictory strategies and policies. Assets are often sold prematurely. An example is technically obsolescent spares. Alternatively depreciable assets operate for many years beyond their planned life expectancy. In addition engineering resource skills and development research are been globally scaled down. Ironically engineering skills appreciate during their life expectancy – compared to depreciating plant and equipment. This has a negative effect on the long-term sustainability of the product. The product being the continuity and sustainability of electricity supply.

This research presents an initial model for representing a “non-financial” balance sheet. Although conceptual and not conclusive, this model represents only plant and equipment. It assumes that asset evaluation is based on the following.

$$\text{Utilisation } (U) \propto \text{Life Expectancy } (L) - \text{Risks } (R) \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (1.1)$$

U is synonymous to the *equity* value in a financial balance sheet. *L* is synonymous to the *asset* value and *R* to the *liabilities*. It assumes the net worth of any utility is its capacity to deliver the required energy demanded, given the remaining life expectancy of its network and anticipated operational risks. Risks are considered as a negative component of the equation. Risk includes the loss of engineering resource skills. The current value of an item of plant is its remaining life expectancy. Each of the above is complex to define and quantify. A solution would be to express each component in percentage or per unit terms. Utilisation (*U*) may be expressed as in percentage and as depicted in equation 1.1 is proportional to *L* and *R*. *L* is expressed in percentage terms and represents the remaining life expectancy as a percentage of the original planned life expectancy. *R* can be expressed in a negative percentage which reduces the remaining life expectancy (*L*).

The model derives its simplicity from the financial equivalent of the balance sheet. The author is aware of the possibility of many alternative models and that the proposed can become the centre of passionate debate. However, this research does not focus on the accuracy of the proposed model. It focuses on deriving an input into the model. The proposed model forms a base from which the objective of this research is initiated and detailed in section *1.2 Definition of the Research Problem and Research Question.*

The importance of an optimally utilised transmission network is not only to provide the required energy transfer capability, but in addition it is to deliver and sustain an acceptable supply voltage waveform within the boundaries of expected operating security risks. Quantitative key performance indicators of performance measures are generally reviewed in isolation and the interdependency between such measures are overlooked. The measurement of transmission network utilisation is not void of such oversight. This section raises the awareness of performance measurement and places it in the context of transmission network utilisation. The main benefit of such measurement serving as a motivation is addressed by reviewing different utilisation improvement strategies. The application and credibility of such a performance indicator can be enhanced if it is normalized with other key dependency variables.

1.3.2 Transmission network performance measurement in perspective.

David Obsborne and Ted Gaebler, authors of *Reinventing Government*, state that performance measurement is a key strategy for developing a results-orientated organisation. They have identified three points is this respect.

- An organisation will not be able to distinguish success from failure if it does not measure results.
- If an organisation cannot recognise success, it cannot reward it. If they cannot reward success they are probably rewarding failure.
- Failure cannot be corrected if it is not recognised.

Performance measures from an electric utility point of view can be diagrammatically represented by *Figure 1.1: The Hierarchy of Performance Measures.* Furthermore this conveys the importance and effect the performance of plant and equipment have on the product offered to the customer. The figure illustrates the dependency of the final product performance on the efficiency of both the plant and equipment. The customer is basically interested in the availability and reliability of the power supply.

Considering that the Product (P) is the end result of production (electricity for utilities), and is a function of both Plant & Equipment (PE) and Operations & Maintenance (OM).

Then: $P \propto f(PE, OM)$ …………… (1.2)

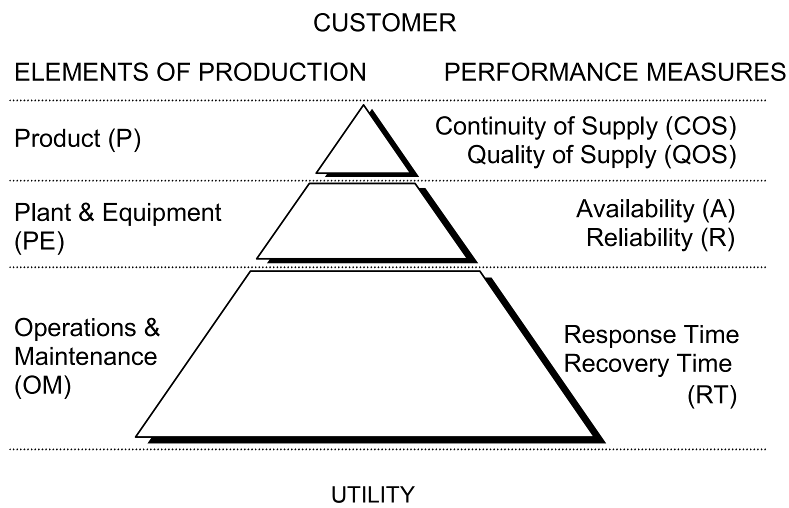


Figure 1.1: The Hierarchy of Performance Measures.

The technical performance of the product is measured in terms of Continuity of Supply (COS) and Quality of Supply (QOS), and is a function of both PE and OM performance measures.

Therefore COS and QOS $\propto f(AR; RT)$ …………… (1.3)

Where AR represents: Availability and Reliability, and RT the Response and Recovery Time.

Overhead transmission line performance has a direct impact on both the COS and QOS of the product. The COS refers to the availability and is measured in System Minutes (SM) with the maximum annual demand used as a base. SM are affected by sustained transmission line outages on radial feeds. The frequency of outages affect the reliability (R). What is not always apparent is the effect of momentary disturbances on the quality of supply of electricity. Transmission line faults cause short duration voltage depressions/dips which result in the tripping of customer process plants. The financial consequence is large in terms of loss of production and re-setup times. One only has to consider the effects to a smelting plant where metal ingots solidify.

A further consequence of excessive line faults is the additional operating duty on plant and equipment. An example is the increased operating frequency of circuit breakers which reduces the interval between maintenance cycles. Considering the former it is of paramount importance that utilities strive to reduce the number of overhead transmission line faults. Transformers are also subjected to high fault currents and depending on the earthing configuration high voltage stresses. Severe lines faults can reduce the transformer life expectancy. Utilities address these affects by applying what is technically and economically achievable. This is achieved by placing surge protection at both the transmission line bay and at the transformer. Furthermore, adequate transformer design specifications against fault currents will reduce transformer failures.

In summary, the key drivers to improve transmission overhead line performance are:

- To sustain the required energy transfer capability of the transmission network,
- To ensure the delivery of an acceptable level of quality of supply, and
- To reduce the fault level impact on terminal plant and equipment.

A widely accepted unit of transmission network utilisation measurement is the percentage availability or non-availability of the network due to unplanned (faults) or planned outages.

1.3.3 Application of benchmarking.

Utilities often spend large amounts on benchmarking initiatives with no return for the efforts and costs. Alternatively promising benchmark exercises are stifled by a lack of interest or dedicated financial resources. Benchmarking should be initiated, supported and driven by senior management. The required resources should be allocated to research potential participants, collect, present, analyse and interpret the results of such studies. To derive the benefits from the study, these results and findings should be converted into strategic plans for the overall improvement of the organisation so as to ensure business sustainability.

The benefits of benchmarking are that participating utilities can become proactive, externally focused and close to the markets they operate in. Furthermore benchmarking provides access to a limitless pool of ideas, and uses the market as a starting point for setting objectives with a sound understanding of customer requirements. Results relevant to transmission network utilisation performance may be applied following the process below. Consider an illustrative example in *Figure 1.2: Typical Transmission Network Unavailability (%) per year* below. This depicts the percentage unavailability of the transmission network due to unplanned and planned outages for each of the 14 participants. The vertical axis denotes 14 electricity utilities and they are ranked in ascending order – the best performer is closest to the horizontal axis and the worst performer the furthest. U_B is the utility under evaluation. The best performing utility is UA and the worst being UC. The first stage of the analysis is to consider the possible causes for performance variations.

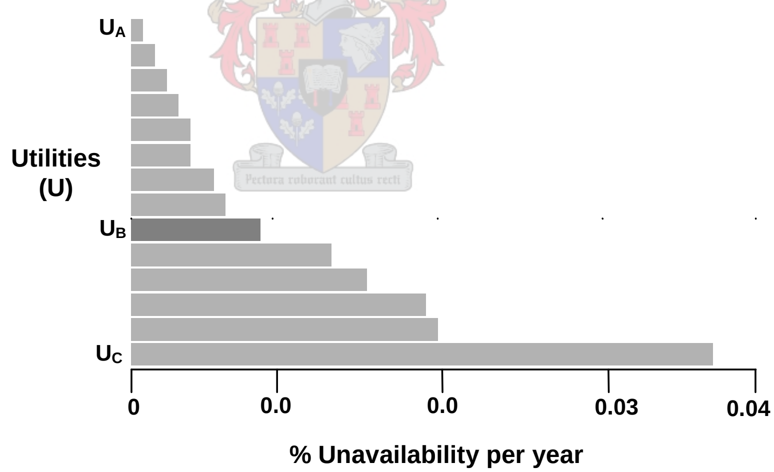


Figure 1.2: Typical Transmission Network Unavailability (%) per year.

Thereafter a realistic performance target must be set. The setting of performance targets for transmission utilisation are driven both internally and externally. Externally they are benchmarked against other utilities, specific customer contractual or supply agreement requirements, regulatory requirements, competitor capabilities and, investor confidence.

Internally they could be management strategy influenced by resources and customer requirements.

A primary driver of transmission utilisation performance is from a regulatory viewpoint. Specified quality of supply (QOS) standards include voltage harmonics, voltage flicker, voltage unbalance, voltage dips, forced interruptions, voltage regulation, frequency and compatibility levels for voltage surges and switching disturbances. Line faults contribute mainly to temporary over-voltage and voltage dips causing the tripping of industries that are electronic process controlled.

The performance of transmission lines has a direct and indirect impact on most of these QOS parameters. The most significant being forced interruptions and voltage surges and switching disturbances.

The interpretation of the QOS indicative targets for the number of voltage dips per year into quantitative terms of transmission line faults (faults/100km) is difficult, if not impossible, as they are dependent on the location of the fault, system load, fault radius of influence, duration of fault, type of fault and fault impedance. Diversity of transmission plant is also a factor.

Setting transmission line performance indicators, using benchmarked results as a basis takes on the following process:

- Review the past actual performance in terms of faults/100km/year from available benchmarked information.
- Review the faults per category of past faults.
- Determine which faults are most likely *avoidable* and which are *most likely unavoidable*.
- Estimate from the controllable faults what faults can be eliminated with a high level of confidence.
- Set realistic targets based on the former.

1.3.4 Performance improvement strategies.

Having quantified the performance target for unavailability, it is now necessary to determine the time frame and the rate at which this target is to be achieved. The purpose of applying a performance improvement strategy along these guidelines is to pace and apply planned and available resources. Refer to *Figure 1.3: Performance Improvement Strategies.* Consider the initial performance level of U_{IS} (initial state), and the improved desired performance level U_{ES} (end state) which is to be achieved over a period of years (from T_{IS} to T_{ES}).

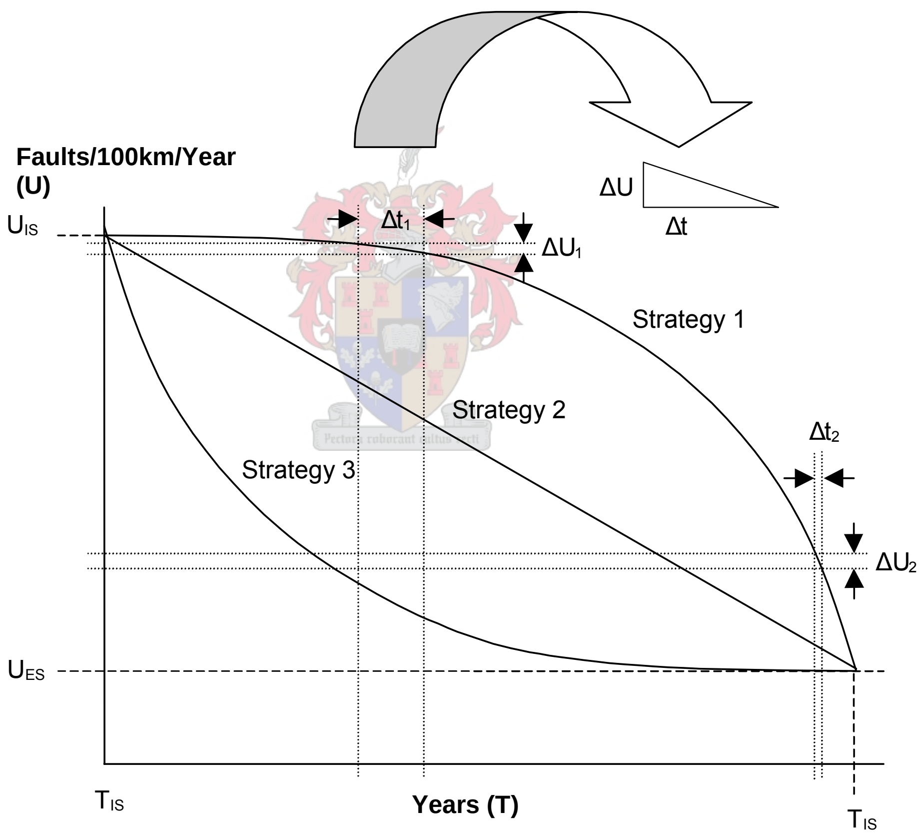


Figure 1.3: Performance Improvement Strategies.

1.3.4.1 Strategy 1.

The rate of performance improvement ($\Delta U_1/\Delta t_1$) during the initial period at Δt_1 is low, and increases towards the later period (Δt_2) by

($\Delta U_2/\Delta t_2$). This is typical were capital intensive action plans are introduced which require medium to long lead times. Such projects would be the refurbishment of transmission lines. Examples are the upgrading of specific creepage distances or a change in insulation materials – from glass discs to non-ceramic insulators. Other examples would be the installation, training of skills and data collection of early warning systems such as lightning and fire detection equipment. Similarly environmental adjustments to servitude management and wild life habitat may not be resolved in the short term.

1.3.4.2 Strategy 2.

A somewhat idealistic strategy would be to follow a uniform performance improvement approach. The rate of performance improvement ($\Delta U/\Delta t$) during both the initial Δt_1 and later periods Δt_2 are uniform. This can be achieved by applying short-medium-long term performance improvement strategies.

1.3.4.3 Strategy 3.

This strategy follows the process of maximum performance improvement within the short term. The rate of performance improvement during the initial period at Δt_1 is high, and decreases towards the later period (Δt_2). This is possible by correcting known line defects and training of staff to reduce operating errors and promote human error programmes such as incentive schemes in the short term. This strategy would not include major refurbishment to the transmission network.

The above are the primary drivers for deriving a composite electrical network utilisation index. In summary, the motivation is twofold. Firstly, determine and benchmark the existing utilisation. Secondly, identify the performance improvement strategy to achieve the former.

1.4 Research Methodology

1.4.1 Type of research.

Compared to traditional ethnography of pure science rather than applied research model, the ethnography of this study contains both a qualitative and quantitative approach. Quantitative in that the data collected is subject to formulaic analysis for the purposes of generating projections. The qualitative approach includes the conceptualising and not the sole reliance on procedural activities. The outcome of this research is largely dependent on the researcher as an instrument and not laboratory measurement. The main attributes of this research being depth and detail of new theory and phenomena neglected by previous researchers and available literature. The research subject and methodology has contained an element of the researchers' personal experience, attributes and skills, as there has been difficulty in aggregating data and making certain systematic comparisons. The research methodology has contained three primary research themes of naturalistic behaviour, flexible research design, and a holistic, panoptic view. The research environment has not been manipulated or controlled within laboratory conditions therefore subscribing to natural occurring events of naturalistic behavior. Variables, hypothesis, sampling and method have been at the least emergent tending towards a flexible research design.

This research has not neglected the overall performance of what unifies the phenomena of a complex and diverse study. Although focused on specific variables, a holistic approach has been adapted. This has involved using multiple methods to collect data to present a more comprehensive overall view. Furthermore this has resulted in cautious progress in reviewing datasets that could have been under-analysed without producing a definitive version of reality and substance to the research. Not neglecting the multifaceted interface of the engineering discipline, this research reaches beyond the defined scope of conservative engineering research methodology. The research boundaries include the dependency between engineering, social, economical, management and environmental dimensions. This is in itself a unique and yet of growing importance in engineering research methodology. A viewpoint not to be confused with, but also not isolated, from the concept of "engineering management."

1.4.2 Subjects of research.

The subjects of the research study can best be illustrated in *Figure 1.4: Hierarchy of the Derivation of the Utilisation Index*. The index must comprise of basically 2 components. Namely, endogenous (internal) and exogenous (external) factors. Both factors have their individual primary variable(s). The endogenous factor consists of two primary variables: Utilisation (U_f) and Reliability (R_f). The exogenous factor consists of a single primary variable: Exogenous (E_f). The subscript $_f$ denotes the final derived primary variable within each category - namely, utilisation, reliability and exogenous.

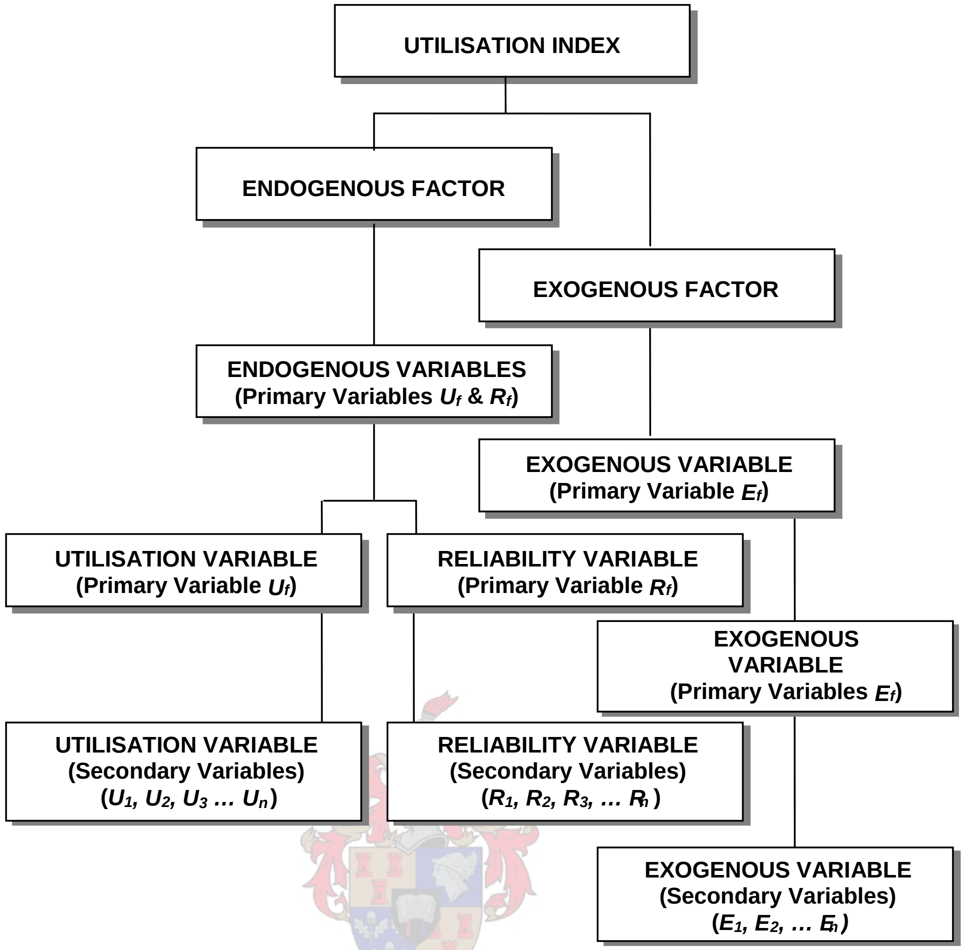


Figure 1.4: Hierarchy of the Derivation of the Utilisation Index

Consider the primary variable utilisation (U_f). The primary variable comprises of secondary variables (U_1, U_2, U_3, … U_n). Their definitions and motivation for choice are documented in section 1.4.4.1. Despite there been numerous performance measures that can measure utilisation, the researcher believes, utilisation consists of performance measures for measuring transmission assets such as transmission overhead lines and installed transformer capacity.

Similarly, the primary variable reliability (R_f), contains secondary variables (R_1, R_2, R_3, … R_n). Again, their definitions and motivation for choice are documented in 1.4.4.2. In essence, reliability refers to the availability and reliability of electricity transmitted via utility transmission networks. Key performance measures include system minutes (availability) and the number of interruptions to the transmission network causing system minutes (reliability).

Lastly, the single variable exogenous, contains only three secondary variables (E_1, E_2, E_3, … E_n). Their definitions and motivation for choice are documented in section 1.4.4.3. Exogenous factors refer to social, economic and environmental considerations.

In addition to the relevant subjects of research, it has been necessary to include the data processing and presentation instruments. This includes the application of software programmes such as XL-STAT Pro Version 4, XLSTAT-Miner 3D, Corel Draw 10 and Microsoft Office.

1.4.3 Data collection source and sample size.

Data source has been obtained via questionnaires, international benchmarking exercises, engineering, social and economic papers. Data from 21 international electric utilities data have been obtained and sourced from the NGC's "International Comparison of Transmission Performance" benchmark exercise. The researcher has been actively involved in the collection of the data and represented Eskom in the collection process.

1.4.4 Data collection variables.

The key *endogenous* input data relate to technical dimensions of the transmission network and the qualitative technical performance. The technical performance includes both utilisation and reliability. Firstly, the utilisation variables are considered.

1.4.4.1 Utilisation secondary variables (U_1, U_2, U_3, … U_n).

The researcher chose four secondary variables for secondary utilisation variables. These were chosen after reviewing the available performance measures in the following documentation.

- NRS 048-1:1996 Electricity Supply – Quality of Supply Parts 1 to 3.

- ESKOM Distribution Standards: Interruption Definitions and Restoration Time Calculations for Distribution.
- ESKOM Distribution Standards: Proposed Performance Benchmark Plan for Distribution.
- Council of European Energy Regulators (CEER): Quality of Supply – Initial Benchmarking on Actual Levels, Standards and Regulatory Strategies.
- CEA Technologies. Power Quality Interest Group: Canadian Distribution Power Quality Survey 2000.
- P1366 – IEEE Trial Use Guide for Electric Power Reliability Indices.
- Network Waitaki Limited Asset Management Plan of 2001.
- IEEE Std 493-1997: IEEE Recommended Practice for Design of Reliable Industrial and Commercial power Systems.
- IEC 77A/356/CDV Electromagnetic compatibility (EMC) – Part 4-30: Testing and measurement techniques – Power quality measurement methods.
- North American Reliability Council: Reliability Assessment 2001-2010.

The researcher's criteria for selecting each secondary variable were based on identifying a relationship between more than one performance measure. For example, the measure of total energy transmitted and the performance of specific transmission plant. The measures in the researched documentation were largely individual measures with no "relationship" between other measures.

The chosen utilisation variables are illustrated in *Figure 1.5: Hierarchy of the Utilisation Variable*. The figure illustrates the composition of the overall utilisation variable U_f consisting of the four secondary variables U_1, U_2, U_3, & U_4. Reference to their individual definitions and the motivation for selecting these specific variables is illustrated.

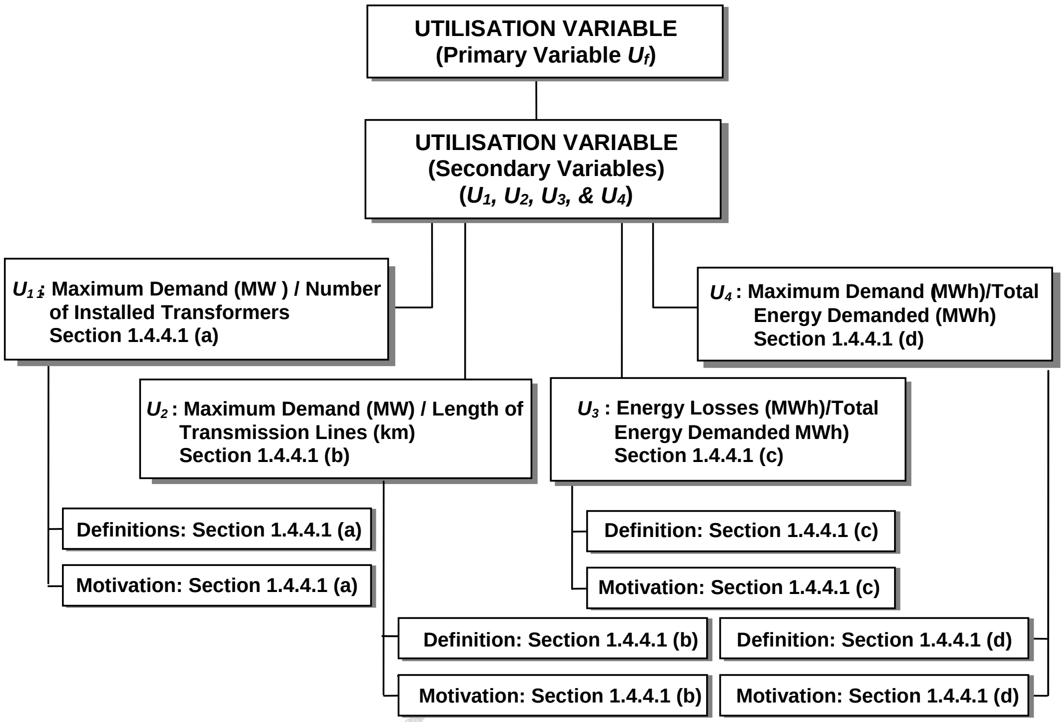


Figure 1.5: Hierarchy of the Utilisation Variable

1.4.4.1 (a) U_1 Maximum Demand (MW) / Number of installed transformers.

Definition:

- Maximum Demand – measured in Megawatts (MW) and defined as annual peak instantaneous energy demand.
- Number of installed transformers – the total number of transmission substation transformers at points of supply and transformation substations. Transformation points are those transformers which do not supply direct load to customers. Instead they transform voltages along the transmission network, e.g. 400/275kV.

Motivation:

The Maximum Demand represents that load from which any further increase in demand would increase the risk of customer load shedding. It can be assumed that the Maximum Demand is close to the operating limits of the transmission network. In many cases, the Maximum Demand is predetermined by the operating constraints of the transmission network – by either current carrying capacity or operational stability such as voltage regulation.

The choice of “number of transformers” as a measurable needs to be justified. An alternative would be the “total installed transformer capacity” measured in MVA. Why has the researcher chosen “number of transformers” as a measurable? Consider the following example of two different utilities ($Utility_a$ & $Utility_b$), each having the same Maximum Demand (MW) and the same total installed transformer capacity (MVA). The example is illustrated in *Table 1.3: Utility Comparison of Maximum Demand/Total installed MVA and Maximum Demand/No. of Transformers*.

Table 1.3: Utility Comparison of Maximum Demand/Total Installed MVA and Maximum Demand/No. of Transformers.

Utility	$Utility_a$	$Utility_b$
Maximum Demand (MW)	1800	1800
No. of Transformers (Unit)	20	5
Size of Transformers (MVA)	100	400
Total Installed MVA	2000	2000
Maximum Demand / Total Installed MVA	***0.90***	***0.90***
Maximum Demand / No. of Transformers	***90***	***360***

The measurement *Maximum Demand / Total Installed MVA* produces the same result for each utility of 0.90. However, the measurement *Maximum Demand / No. of Transformers* produces different results of 90 and 360. The researcher views this as important as the latter measurement provides an indication of the "average" size transformers and the inherent risk to the supply should a transformer trip. It can be seen that *Utility*$_b$ is at a higher risk – in the above example *Utility*$_b$ would have to shed customer load of 200MW. *Utility*$_a$ on the other hand, can afford to lose two transformers before load shedding takes place.

It is for this reason that the researcher has chosen the measure *Maximum Demand / No. of Transformers* as the utilisation secondary variable U_1.

1.4.4.1(b) U_2 Maximum Demand (MW) / Length of transmission lines (km).

Definition:

- Maximum Demand – as in 1.4.4.1.a
- Length of transmission lines – the total length of transmission cable and overhead transmission lines (km). This includes all voltage ranges.

Motivation:

Similar to 1.4.4.1 (e) the measure Maximum Demand is related to another crucial item of transmission plant – namely, transmission lines. The measure provides an indication of what the Maximum Demand (MW) is per unit length of transmission lines (km). This provides a useful indicator for trending transmission line utilisation. In addition, this measure provides a useful benchmarking guideline for electricity utilities. The study has not separated the transmission lines into separate voltage categories. Although a more accurate approach would be to distinguish and include the various voltages; the researcher does not deem this an essential contribution as the intent is to develop a "high-level" overall measure and indication of transmission line utilisation.

1.4.4.1(c) U_3 Energy losses (MWh) / Total energy (MWh).

Definition:

- Total Energy Losses – difference between the power measured imported directly from generation or imported from other neighbouring transmission networks, and the energy measured at the metering points at which the power leaves the transmission system. Units are in MWh.
- Total Energy Demanded – measured in Megawatt-hours (MWh) and defined as total annual MWh delivered from the transmission network. It excludes MWh not supplied due to transmission faults or outages (planned or unplanned outages).

Motivation:

The measure of energy losses (MWh) / Total energy transmitted (MWh) will provide an indication of how efficiently the network is being utilised. Again, this provides a “high-level” performance measure and is subject to many variables. When comparing utilities against each other, voltage levels and the magnitude and length of high level voltage circuits will affect results. Energy losses will be higher at lower voltage levels. A further consideration would be the network configuration and the operational duration of less efficient (higher energy losses) transmission networks. The availability of voltage regulation plant such as capacitors, reactors, SVC’s and transformer tapping facilities will also affect the energy losses.

1.4.4.1(d) U_4 Maximum Demand (MW) / Total Energy Demanded (MWh).

Definition:

- Maximum Demand (MW) – as in 1.4.4.1.(a)
- Total Energy Demanded (MWh) – as in 1.4.4.1.(c)

Motivation:

The above measurement provides an indication of the maximum utilisation in relation to the total energy transported. One would expect that electric utilities at the same system voltage and with a low value of U_4, are more effectively utilising their transmission networks than electric utilities with lower values. *Figure 1.5: U_4 for Constant Maximum Demand (10 units)* represents this relationship considering a constant maximum demand with increasing total energy transported. Similarly, the relation with a constant total energy and varying maximum demand can be established.

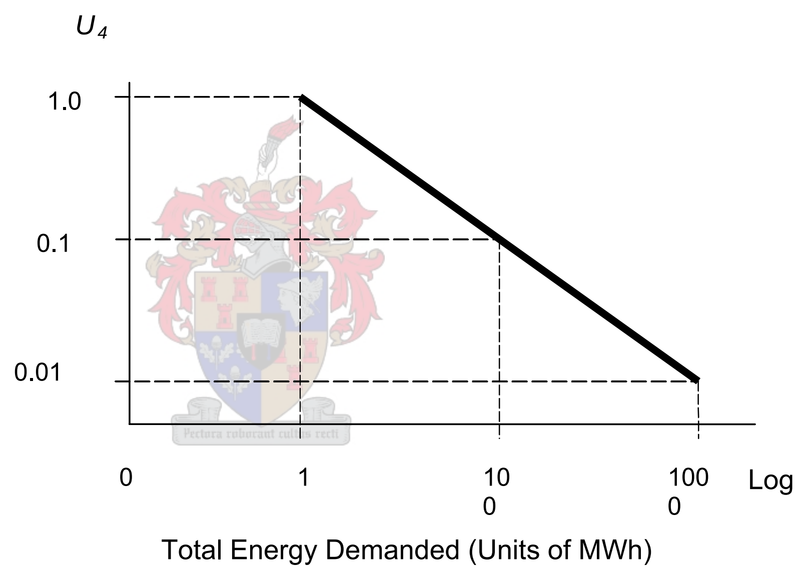


Figure 1.5: U_4 for Constant Maximum Demand

1.4.4.2 Reliability secondary variables (R_1, R_2, R_3, & R_4).

The researcher acknowledges the contributions of Roy Billington, Ronald N. Allan and Luigi Salvaderi in the field of reliability assessment in power systems [1.1], [1.2] [1.3]. Much of their contribution is towards the valuation of different concepts, models and techniques used to assess reliability in the planning and operation phases of grid development. Furthermore their research includes numerous studies relating to the "assessment of reliability worth" [1.4] or the cost of unserved energy. Similarly, the IEEE Recommended Practice for Design of reliable Industrial and Commercial Power Systems (IEEE Std 493-1997) [1.5] is directed towards the end electricity user. The difference between transmission and distribution networks as interpreted by the researcher is discussed in Chapter 5: *Reliability Under Discussion*. Not neglecting the studies of Roy Billington, the researcher's objective is to produce a high level organization measure which represents reliability in relation to availability in terms of maximum demand and total energy consumed.

As for utilisation secondary variables, the researcher choose four secondary variables for secondary reliability variables. Again, these were chosen after reviewing the same documentation as listed in the utilisation section.

As for the utilisation secondary variables described in section 1.4.4.1, the reliability secondary variables are illustrated to facilitate easier overview and reference. These are illustrated in *Figure 1.6: Hierarchy of the Reliability Variable*.

The relevant definitions and the motivation for each are contained in section 1.4.4.2 (a) to 1.4.4.2 (h). It must once again be emphasised that the intent of the measurable must be a "high-level" input into facilitating senior management decision-making. The purpose of reliability secondary variables is to include both continuity and quality of supply measures.

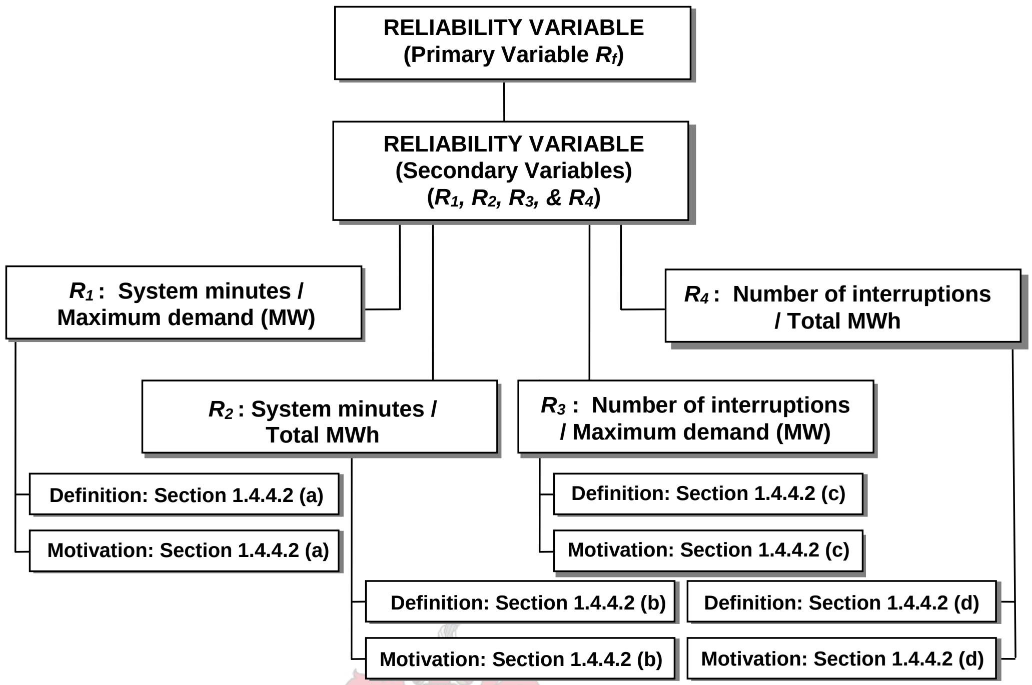


Figure 1.6: Hierarchy of the Reliability Variable

1.4.4.2 (a) System Minutes/Maximum Demand (MW) [R_1]

Definition:

- System Minutes (SM) measures unsupplied energy = (Load Interrupted [MW] x Duration [minutes]) / (Annual System Peak [MW]). One System Minute is equivalent to an interruption of the total system load for one minute at the time of annual system peak demand. The Eskom Annual System Peak used is the figure for the previous year. (In the Southern Hemisphere the annual peak invariably occurs in the middle of the year in winter.) It is a measure of continuity of supply.

- Maximum Demand – as in 1.4.4.1 (a).

Motivation:

System minutes is a measure of the “discontinuity” of electrical supply. It provides an indication of the disruption of customer service due to either controllable or uncontrollable influences. Controllable influences are those factors which the electric utility can influence by applying corrective action. Such include (but not conclusively): refurbishment of networks, condition monitoring of electrical plant, review of maintenance practices, and the development of operational and maintenance skills.

1.4.4.2 (b) System Minutes / Total MWh [R_2].

Definition:

- System Minutes – as in 1.4.4.2 (a).
- Total Energy Demanded (MWh) – as in 1.4.4.1(c)

Motivation:

R2 is a measure of “discontinuity” as is R1 but expressed in terms of Total Energy Demand (MWh). The motivation remains the same as for 1.4.4.2 (a).

1.4.4.2 (c) Number of Interruptions / Maximum Demand (MW) [R_3].

Definition:

- Number of interruptions – measured in units, are faults which have resulted in the loss of energy supply and/or the automatic opening and reclosure of a supply circuit breaker.
- Maximum Demand – as in 1.4.4.1 (a).

Motivation:

Number of interruptions is a measure of “quality of supply” and provides an indication of the frequency of supply disruptions. Expressed as a function of maximum demand, provides an indication of the quality of supply at the worst operating condition of a network.

1.4.4.2 (d) Number of Interruptions / Total Energy Demanded (MWh) [R_4]

Definition:

- Number of Interruptions – as in 1.4.4.2.(c)
- Total Energy Demanded (MWh) – as in 1.4.4.1.(c)

Motivation:

Again, the number of interruptions is a measure of “quality of supply” and provides an indication of the frequency of supply disruptions. Expressed as a function of total energy demand, it provides an indication of the quality of supply during the annual energy transmitted via a transmission network.

1.4.4.3 Exogenous secondary variables (E_1, E_2, & E_3).

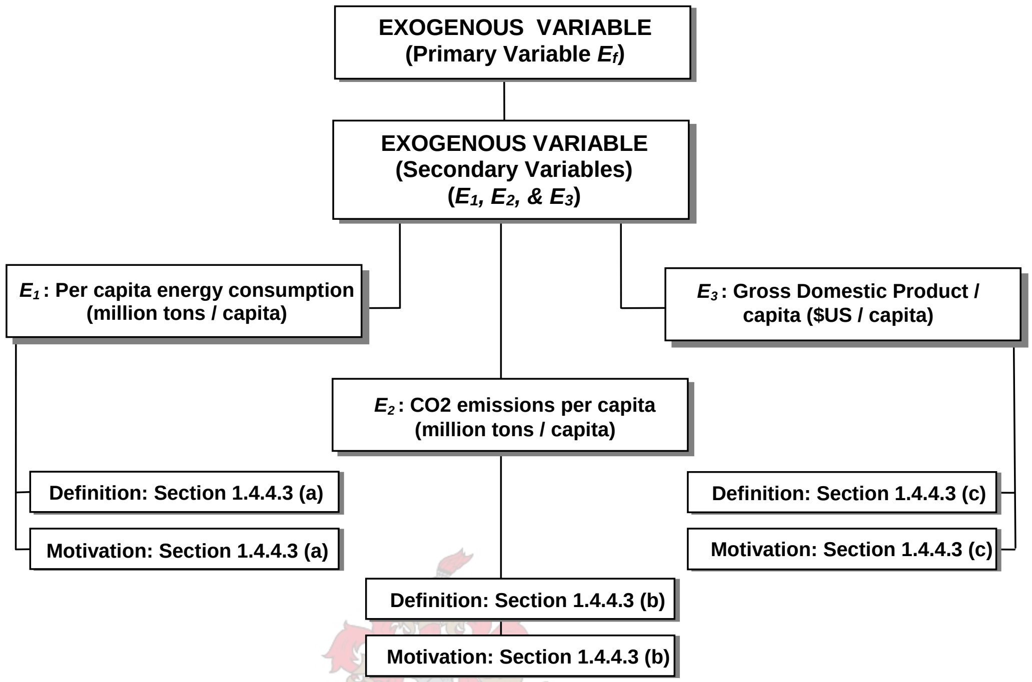


Figure 1.7: Hierarchy of the Exogenous Variable

The key *exogenous* input data relate to social, economic and environmental performance. The following input data was selected.

1.4.4.3 (a) Per capita energy consumption (million tons / capita) [E_1].

Definition:

The amount of energy consumption per capita (population) by end-uses and sources in tonnes of oil equivalent (TOE) per year. Energy source includes liquids, solids, gases and electricity and is given per country.

Motivation:

Energy is a key factor in industrial development and in providing vital services that improve the quality of life. Traditionally energy has been regarded as the engine of economic progress. However, its production, use, and byproducts have resulted in major pressures on the environment, both from a resource use and pollution point of view. The decoupling of energy use from development represents a major challenge of sustainable development. The long-term aim is for development and prosperity to continue through gains in energy efficiency rather than increased consumption and a transition towards the environmentally friendly use of renewable resources. On the other hand, limited access to energy is a serious constraint to development in the developing world, where the per capita use of energy is less than one sixth that of the industrialised world.

1.4.4.3 (b) CO_2 emissions per capita (million tons / capita) [E_2].

Definition:

The amount of total CO_2 emissions measured in million tons per population of a specific country.

Motivation:

The Kyoto Protocol was drawn up in Japan in 1997 to implement the United Nations Framework Convention on Climate Change (UNFCCC). Its objective is to reduce emissions of carbon dioxide and other greenhouse gases by establishing reduction targets and by developing national programmes and policies. Kyoto attempted to uphold a new environmental standard and has succeeded in raising the profile of global warming, and in highlighting the difficulties involved in international co-operation on environmental matters.

Aggregated emissions of Kyoto basket of 6 greenhouse gases. Indexed 1990=100, based on CO2 equivalents. This indicator measures the anthropogenic emissions of the greenhouse gases carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4) and three halocarbons, hydroflourocarbons (HFCs), perflourocarbons (PFCs) and sulphur hexaflouride (SF_6), weighted by their global warming potentials (GWPs). The GWPs relate to the ability of the different gases to contribute to global warming over a 100 year time horizon. GWPs are calculated by the Intergovernmental Panel on Climate Change. The figures are given in CO_2 equivalents. The indicator does not include ozone depleting substances with global warming properties covered by the Montreal Protocol (1997). Recent studies and research provide scientific evidence that increases in the atmospheric concentration of greenhouse gases (due mainly to human activities) give rise to climate change.

The Kyoto Treaty represented an attempt to increase and set mandatory targets to tackle climate change. It binds industrialised nations to reduce worldwide emissions of greenhouse gases by an average of 5.2% below their 1990 levels. Under the Kyoto Treaty the US agreed to cut its carbon emissions by 7%. As of 2001, it stood at a level about 13% above 1990 emissions. The EU agreed to cut its carbon emissions by 8%; in 2001 it stood at a level about 0.5% above 1990 emissions. Japan agreed to cut its carbon emissions by 8%; in 2001 it was around 2.7% above its 1990 emissions level (The Globalist 2001). Developing countries were left exempt from the targets.

However, the US pulled out of this commitment in March 2001, and President Bush has stated that the US will never sign the treaty. The Bonn Compromise, reached in July 2001, is a limited version of Kyoto lowering the requirements to about 2% below 1990 emissions. However, it is questionable to what extent Kyoto can survive and succeed without participation by the US. In order to become international law, the treaty needs to be ratified by a minimum of 55 countries, and it requires ratification by the nations that accounted for 55% of the industrialised world's CO2 emissions in 1990. The EU's decision that its 15 member states would ratify by 1 June means the first criteria has been met - 65 countries have so far ratified. Further negotiations are underway in Japan and Russia; however, there is strong opposition in Canada and Australia. According to the Intergovernmental Panel on Climate Change (IPCC), without active efforts to reduce emissions, the planet is expected to warm by an unprecedented 2.5-10 degrees F during the 21st century (Baumert & Kete 2001).

1.4.4.3 (c) Gross Domestic Product / capita ($\$_{US}$ / capita) [E_3].

Definition:

Gross Domestic Product (GDP) is the total output of goods and services for final use produced by an economy, by both residents and non-residents, regardless of the allocation to domestic and foreign claims. It does not include deductions for depreciation of physical capital or depletion and degradation of natural resources. Gross Domestic Product per capita is the GDP divided by the total population within a country during a specified period.

Motivation:

GDP per capita provides an indicator of purchasing power parity per person of the population.

This concludes the selection of the specific secondary variables for all primary variables. These variables will be discussed in detail in further chapters.

1.5 Structure of the Dissertation

The dissertation comprises of 8 chapters of which the following is a brief overview and the expected length of each.

Chapter 1: BACKGROUND INFORMATION (40 Pages)

Provides a background to the new challenges facing electricity utilities specific to providing reliability and availability in the face of increasing competition, regulation and privatisation. The concept of a "non-financial" balance sheet is introduced emphasing that the survival of any organisation is not only dependent on financial indicators. The research methodology introduces the type of research, subjects of research, data collection source, data collection sample size and data collection variables. Definitions and the motivation for these variables are included. These are discussed in more detail in Chapter 3.

Chapter 2: LITERATURE RESEARCH (23 Pages)

Reviews literature research relating to the main subsections of the topic, namely endogenous and exogenous variables. A brief evolution of energy demand patterns is provided. International energy demand patterns are reviewed and the variations in growth patterns between industrialised and developing countries are compared. The benefits and mention of main international benchmarks are discussed. Capacity utilisation and power security provides a backdrop to the subject of transmission utilisation. The chapter concludes with a review on economic output energy relationships.

Chapter 3: DATA COLLECTION, PROCESSING AND EVALUATION METHODOLOGY (13 Pages)

Discusses the data collection and evaluation methodology. In more detail the source of data, sample size, specific data (both endogenous and exogenous) are presented. The statistical limitations and assumptions, model of confidence, selection of multivariate techniques, multivariate data matrix and the procedure for factor analysis are conveyed.

Chapter 4: PRIMARY VARIABLE "UTILISATION" UNDER DISCUSSION (43 Pages)

The collection, evaluation, processing and presentation of utilisation variables are documented in detail. This includes the criteria used in selecting these specific performance measures and the selection process to derive at one overall measure. An in depth discussion of the processing of the results and assumptions used around the data base will be presented.

Chapter 5: PRIMARY VARIABLE "RELIABILITY" UNDER DISCUSSION (47 Pages)

The collection, evaluation, processing and presentation of reliability variables are documented in detail. This includes the criteria used in selecting these specific performance measures and the selection process to derive at one overall measure. An in depth discussion of the processing of the results and assumptions used around the data base will be presented.

Chapter 6: PRIMARY VARIABLE "EXOGENOUS" UNDER DISCUSSION (25 Pages)

The collection, evaluation, processing and presentation of exogenous variables are documented in detail. This includes the criteria used in selecting these specific performance measures and the selection process to derive at one overall measure. An in depth discussion of the processing of the results and assumptions used around the data base will be presented.

Chapter 7: DISCUSSION EMANATING FROM THE RESEARCH RESULTS (16 Pages)

Observations of the research results are conveyed and discussed as well as specific aspects emanating from the research study.

Chapter 8: APPLICATION OF THE TRANSMISSION NETWORK UTILISATION INDEX (12 Pages)

An insight is provided into the contribution this research has on the performance measurement of electricity utilities. It attempts to answer the "who benefits and why" from this research study. It provides a practical aide for senior management and engineers to evaluate the operational state of the organisation in terms of utilisation and reliability. If required, the socio-economical dimension may also be assessed. The individual primary variables are considered as well as the secondary primary variables. The overall utilisation variable U_f has been included in the discussion.

Chapter 9: CONCLUSION (6 Pages)

The dissertation concludes with the overall summary of the motivation for initiating the research, the evaluation of achieving the research aim and objectives, further developments of the model, and finally recommendations into further research regarding comparative electrical network utilisation.

REFERENCES

A comprehensive, and accurate list of all references is provided for the reader to cross reference against more detailed documentation.

APPENDIX 1: Example of Electricity Utility Raw Data

Chapter 2

LITERATURE REVIEW

Chapter Objective

This chapter's objective is to provide an insight into the evolution of the electricity market and a brief overview of related topics pertaining to this research study. A comprehensive literature review would consume a large volume of the dissertation. Therefore, only what the researcher deems relevant has been included in this section. There are however, references made in the remaining chapters to particular contributing references.

2.1 Chapter Overview

Reviewing existing literature research on the *"derivation on a composite electrical transmission network utilisation index"* is challenged by the fact that this specific topic has not been superficially discussed in areas of network planning and international electricity utility benchmarking exercises. Although being an integral part thereof, one must not view reliability indices, availability and risk analysis as been the same as *utilisation*. Although these former topics have been extensively researched, the challenge is to select the appropriate references among the labyrinth of existing technical papers. The need to research the basics to support the derivation of such an index is, however, of paramount importance. Utilisation of an electrical transmission network stems from matching the transmission network energy transfer capability to the varying customer load requirements within the constraints of social and environmental expectations. These constraints are ever increasing in modern society.

Forecasting customer electricity energy requirements is a crucial aspect and the growth thereof correlates to national and international economic growth. It is therefore deemed fit that *a historical overview of world economic growth* and *energy consumption* provide an initial setting for the need to more effectively utilise existing and future electrical transmission networks, plant and equipment. A study of the evolution of electricity consumption can enhance forecasting methodology which consequently leads to an improvement in transmission network planning.

"… the future is in the past …" is not all that remote from reality.

Of equal importance is the ability to forecast future trends in the energy consumption and identify which types of energy and geographical areas are affected and to what extent. The consequential effect that such energy consumption has on environmental issues is important for forecasting the future expectations regarding energy sources and the location thereof. Furthermore a distinction should be made between the developing countries and industrialised countries as the future growth in energy demand and energy sources are different in both instances. A brief overview and the stressing of the importance of the main forecasting techniques and their methodological will be discussed and their limitations and potential to further development questioned.

All electrical utility benchmarking efforts would be virtually impossible to source as they cover from broad organisational performance measurement to specific plant and equipment studies. Only limited benchmarking studies appropriate to this study will be discussed with particular reference to availablity and reliability of transmission networks. The main contribution to this section is the most recent results as presented by the National Grid Company's *International Comparison of Transmission Performance*. Unfortunately, due to copyright and confidentiality the names of utilities and countries have been omitted – utilities are referred to as U_{1to22} and countries C_{1to13}. The Edison Electrical Institute with it's custom benchmarking questionnaire and work group is discussed. The methodology of the increasingly used International Transmission Operations and Maintenance Study is reviewed. The section concludes with the authors' viewpoints of the main limitations regarding international benchmarking.

A section is devoted to power system security which stems directly from the network utilisation of a transmission network. The script reviews the theory and highlights the deficiencies which could be addressed by this academic study. Current initiatives regarding the measurement of sub-transmission capacity utilisation will be topical in this study. This includes the utilisation of sub-transmission lines and transformer installations. The limitations and potential for further studies towards this measurement will also be discussed. In addition the results of CIGRE WG 31: Transmission Systems on the increased circuit loading and corridor utilisation will be reflected on. This section will review the various methods currently researched to enhance circuit loading from a quantitative and qualitative point of view.

The review on literature research concludes with the concept of long-term power system security as defined in terms of adequacy and security. Power system security brings into perspective the reality of increasing the utilisation of the network to the threshold of *feasibility* and *adequacy* - a critical dimension in the pursuit of deriving a composite utilisation index.

2.2 Historical Overview

2.2.1 Postwar Period.

The postwar era of the 1950's and 1960's witnessed rapid economic growth during which the focus on highly accurate energy forecasting and efficient utilisation of electrical transmission networks was not considered a high strategic or operational business priority. During that period most electrical utilities had large excess generation when compared to energy demands. Similarly transmission networks had excess transfer capabilities so inaccuracies in the under-estimation of energy demands in electricity forecasts were absorbed by this excess generation and network transfer capability. Most electrical utilities were state or public owned organisations posing little restriction on capital growth expenditure. Expansions to generation capacity and transmission networks experienced large incremental step changes partly due to the long lead time from requirement identification to the commercial operation of power stations and subsequent transmission network.

2.2.2 First Oil Crisis.

This postwar period was followed during the late 1960's by the realisation that sustaining the previously attained economic growth was unrealistic. This was period that witnessed the rising of the Eastern economy posing an increasing competitive threat to Western economic growth. The uncertainty that followed brought about the publishing of the report compiled by the club of Roma on "Zero growth". This period was furthermore aggravated by the first oil crisis of 1974-1979 which resulted in a reduced economic growth, higher energy prices and policies promoting energy saving policies. Main European countries such as Belgium, France, Italy, Sweden and the U.K. exepirienced a reduction of industrial energy consumption during this period as depicted in Table 2.1. *Energy Consumption in Industry (average annual growth % rates).*

Table 2.1: Energy Consumption in Industry (average annual growth % rates)

	1960-1973	1973 -1979	1979-1983
Belgium	6,8	-1,6	-5.6
FRG	4,6	-1,2	-2,7
France	5,1	+1.4	-3,8
Italy	8,1	-0.6	-4,1
Japan	11,0	+0.4	-4,4
Netherlands	10.6	+4.4	-9,0
Norway	5,9	+2.2	-0,8
Spain	10,5	+2.8	-2,7
Sweden	4,4	-0.4	-2,9
U.K.	3,1	-2.0	-6,6
USA	3,2	+0.8	-5,6

Source: OECD

2.2.3 Second Oil Crisis.

This pattern was further entrenched after the occurrence of the second oil crisis between 1979 and 1983 during which the former countries experienced a reduction of up to 25%. Due to the oil crisis during the period between 1973 and 1979, the growth for electricity consumption grew faster than for other fossil fuels. The further growth for electricy demand had to rely on a increase in growth of different economic sectors or a change in the pattern of social structures and behaviours.

The above is illustrated in *Table 2.2: Electricity Consumption in Industry (average annual % growth rates)* and *Table 2.3: Percentage Share of Electricity in Industrial Energy Consumption*.

Table 2.2: Electricity Consumption in Industry (average annual % growth rates)

	1960-1973	1973 -1979	1979-1983
Belgium	8,2	1,9	1,7
FRG	6,2	2,2	1,2
France	6,7	2,5	0,5
Italy	6,9	3,1	1,6
Japan	11,2	2,3	1,5
Netherlands	9,8	4,2	2,0
Norway	5,8	1,3	1,1
Spain	11,1	2,9	0,1
Sweden	5,5	0,9	1,0
U.K.	4,1	0,9	5,0
USA	3,5	2,9	1,4

Source: OECD

Table 2.3: Percentage Share of Electricity in Industrial Energy Consumption

	1960	1973	1979	1983
Belgium	19,5	23,2	28,6	33,8
FRG	24,5	29,9	36,5	38,7
France	25,0	33,5	35,8	42,7
Italy	33,0	28,5	35,4	39,3
Japan	34,9	35,5	39,7	46,8
Netherlands	23,4	21,1	20,9	28,2
Norway	72,3	71,8	68,2	73,4
Spain	30,5	32,9	40,1	44,4
Sweden	36,1	43,0	46,0	53,5
U.K.	23,1	26,1	31,1	33,4
USA	26,7	27,6	31,2	35,8

Source: OECD

The economic impacts from the oil crisis made utilities more aware of the importance of accurate planning and more conservative investment decision making. Excess capacity from previous investment decision making was now costing utilities dearly on operational and capital repayment. Further uncertainties appeared on the future of energy prices and the possibility of evolving price structures. The former uncertainties strengthened the need to accurately forecast electricity energy demand. Future expansion on transmission networks was dependant on accurate demand forecasting and short periods between planning and commercial operation.

2.2.4 Environmental Issues.

1974 saw the rising of environmental concern. Utilities were bruntly made aware of the importance of accurate energy demand forecasting. With the increasing effect of spirally fuel costs having on production costs, electrical utilities had to focus on accurate forecasting or suffer financial losses. Economic growth uncertainties and political instability made accurate electricty forecasts more important. Included in this expansion to transmission network were small incremental increases with a short planning to commercial operation

World population and economic growth will remain the key drivers for the development in energy markets. Comparing the growth for energy demand in industrialised and developing countries, it becomes evident that the demand for energy has weakened in industrialised countries and increased in developing countries. Electricity demand forecasts cover the short-term operational management issues as well as long-term investment planning.

Electrical utilities have also evolved from separate and independently operated electric companies, to interconnected transmission systems. This initially offered economic, reliability and operational advantages. Furthermore a code of mutual assistance evolved whereby utilities would offer resources in the form of sharing power reserves, restoration crews, and equipment to restore supply. The fact that transmission of electricity follows the path of least resistance and that energy cannot be stored, made the coordination of expansion planning and capacity utilisation an increasing factor among electricity utilities.

Additional factors negatively impacting the growth of transmission systems. These are:

- Gaining access to transmission line servitudes is becoming extremely difficult.
- The rate of return prescribed by regulating bodies discourages the attraction of capital for the financing of new investments.
- Public opposition to new facilities can keep utilities from building new transmission lines.
- Along with aesthetics, electric and magnetic fields (EMF) has caused the public to be opposed to the construction of transmission lines.
- Environmental concerns such as air emissions has caused generating units to be located at a distance from the load centers.

2.2.5 Current Situation:

Current electrical utilities are under pressure from regulators and stakeholders to ring-fence their core business of transmitting electricity. The privatisation of additional services has developed to such an extent that electrical utilities have now formed global organisations extending beyond their initial scope of generating and transmitting of electricity. Within the newly formed scope includes technological services, transmission capacity marketing, international projects, life-cycle management and the design, production and sale of alternative energy products. Companies who have taken the lead in the former are TransEnergie of Hydro-Québec and National Grid plc.

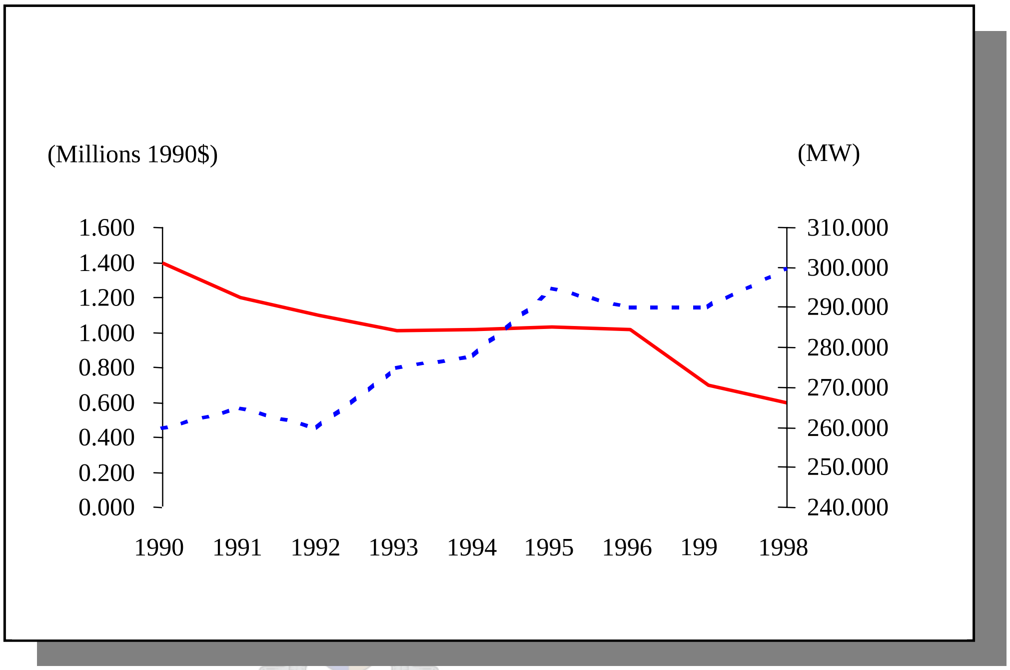
This trend has also integrated the engineering fraternity into other domains such as environmental, economic, social and political disciplines.

Modern electricity utilities are continually under pressure to recover operational and expansion costs within a regulated price structure. The basis of providing electricity is being viewed more as a community service without neglecting the real benefit and driver of national economic growth.

2.2.6 Summary

During the last thirty years of the electricity industry evolvement, there were two primary factors that influenced the course of events. The first was an economic factor that witnessed electrical utilities investing in large power plants along the theory of large-scale economy. The second factor was the development of technology. With new technology electrical transmission networks could expand over greater distances and at higher voltages with a minimum loss of power along the way. Smaller generation units of 100MW capacity could be built within a year compared to the previous 10 year period for 500MW units. Furthermore these smaller units were producing cleaner and cheaper electricity.

However, the current situation is that transmission investment is not keeping pace with demand growth. This is clearly depicted in *Figure 2.4: U.S. Net New Transmission Investment vs. System Peak Demand.* The red line depicts the fall in transmission investment and the broken blue line depicts the increase in demand growth.



Source: PA Consulting based on data from the UDI

Figure 2.4: U.S. Net New Transmission Investment vs. System Peak

2.3 Reliability Indices

Reliability is becoming an increasingly competitive advantage in electric utility networks. Furthermore, it is a performance measure that has been, and is continually being researched from a practical investigation, to statistical analytical studies. EPRI PEAC [2.3.1] has produced practical findings relating to identifying:

- the most common reliability indices,
- major events attributing to unreliability,
- variables affecting reliability indices, and
- general ways to improve reliability.

The most commonly used benchmarked reliability indices are system average interruption frequency index (SAIFI), and system average interruption duration frequency index (SAIDI).

2.4 Power System Security

2.4.1 Background

Past years witnessed strong networks proposed by system planners, and network operators operated with large security margins. Coupled to the high network reliability were relatively high investment and operational costs. Economic imperatives and pressure from regulatory bodies have caused utilities to operate at lower security margins, thereby increasing the network utilisation and reducing spinning reserve on generation capacity. This resulted in a change from the traditional and conservative deterministic approach, to an approach that would take into account the probabilistic nature of numerous variables for effective decision making.

Planning criteria was initially based on a deterministic method which produced a minimum reliability for the entire transmission network and to limit the risk of extended and uncontrolled propagation of disturbances. The general stability of the system was defined within respect to voltage amplitude, angle and frequency. Probable contingencies considered the consequences where:

- Network stability was maintained with *local* disturbance consequences such as in the case of a point of supply (substation).
- System stability was maintained with *regional* disturbance consequences as a section of the network.
- System instability is accepted and a major loss of supply or blackout is expected.

Recent planning criteria are based on probabilistic methods that rely more on system performance statistics. There is, however, the risk of applying "too short a time base" in determining probabilistic criteria. Electrical plant has a long-term life expectancy and development in diagnostic condition monitoring has only been recently applied. The other factor affecting probabilistic methods is the change in design standards and methods. Previous designs were based on hand calculated methods whereas modern designs are presumed to be more accurate due to computer aided simulation and extensive research development in high voltage disciplines. If would be fair to state that modern plant are designed and constructed closer to the operational limits than previously due to design methods and the increased competition between manufacturers – each striving to reduce manufacturing costs. This will impact on probabilistic methods during the life expectancy of newer plant.

There is however, a further risk when applying probabilistic methods, of neglecting or avoiding the "force majure" induced disturbance which is generally catastrophic. A case in point is the incident in Canada during 1998 when HYDRO Quebec experienced a total blackout for a period of 2 days.

2.4.2 CIGRE Task Force 38.03.12.

The CIGRE Task Force 38.03.12 produced a position paper in December 1997 that addressed the issue of power system security assessment with specific attention to proposed steps in determining a probability security assessment: These steps are as follows.

Step 1: Initially an assumption is made of a prior probability distribution of static and dynamic models of a power system with its possible pre-contingency states. This is dependent on the decision-making content (ctxt) and available information (info) available.

p (model, state $\mid$ ctxt, info)

Step 2: Assume a conditional probability distribution of all possible disturbances according to the context and the information at hand.

p (disturbances $\mid$ ctxt, info, model, state)

Step 3: Define a severity function that evaluates the severity of a particular scenario in terms of its consequences.

severity (ctxt, info, model, state, disturbances)

Step 4: Evaluate the overall risk as the expectation of severity.

Risk (ctxt, info) $\equiv$ $\int_{dist}$ *severity* (ctxt, info, model, state, disturbances)

x p (disturbances $\mid$ ctxt, info, model, state) x p (model, state $\mid$ ctxt, info)

Step 5: Evaluate an investment decision by summing up its corresponding operating and investment costs against the overall risk.

2.4.3 Developments in the Model.

The application of the above model is feasible towards developing a transmission utilisation index providing the following is to be included.

- Considering *p* (disturbances | ctxt, info, model, state). The disturbances as defined in the probability function must include quality of supply parameters and not be exclusive to loss of supply parameters.
- Similarly the expectation of severity within the function *severity* (ctxt, info, model, state, disturbances) must include the former.

By including the above the overall risk would be comprehensive in that both the quality and continuity of supply will be included.

2.5 Capacity Utilisation Measures

2.5.1 CIGRE WORKING GROUP 31: Transmission Systems

One of the three preferential subjects dealt with by the CIGRE WG 31 was increasing the circuit loading and corridor utilisation of transmission systems. Proposals on the merit for corridor utilisation were tabled and raised interesting aspects such as power density measurement and visual impact assessment. Power density [P] (MW/m^2) is expressed as:

$$[P] \quad = \quad P/4W \times H$$

where, P is the transmitted power in *MW*, W is the horizontal distance between outermost conductors, and H is the average height of the uppermost power-carrying conductor.

The enhancement of current loading on existing networks can be considerable by the effective use of probabilistic treatment of transmission line loading and ambient weather parameters.

R Stephen & R Smit of ESKOM (RSA) did ground work in attempting to measure the capacity utilisation of the sub-transmission network. Its primary objective was to ensure the measurement of both a return on investment and the productivity of the installed network. The philosophy is based on ideally matching the sub-transmission line capacity utilisation with the installed transformer capacity utilisation. In this model the capacity utilisation is limited to the weakest network constraint being either thermal limitation or operational stability. Peak demand conditions were used for the derivation of the capacity utilisation indicator.

2.5.2 <u>Transformer capacity utilization</u>.

Key assumptions were made of which the most salient are: the past 14 months were used to determine the peak maximum demand, only HV/MV transformers were included and the load off tertiary transformers were excluded from consideration.

The transformer capacity (MVA-c) are calculated as follows:

MVA-c = *NR x MVA-t*

Where:

NR = Number of transformers per substation

MVA-t = Specific transformer size

2.5.3 <u>Sub-transmission line capacity utilization</u>.

As for transformers key assumptions were made of which the most salient are: cable ratings were as per manufacturers, line capacity was based on the 75^{o}C deterministic limit in Ampere, Tap Seppa's formula is applied, ampacity is not representative of the line's capability, the deterministic rating is limited to the smallest conductor rating of multiple conductors on the same line, network configuration and shunt compensation is ignored.

2.5.4 Further Developments.

Transmission electrical networks are similar to distribution network other than transmission networks that are often populated with "transforming substations" which do not provide direct load. This creates the opportunity to measure utilisation of substations from a point of supply (installed transformer capacity and customer firm supply), as well as from an overall transmission network (inclusive of transforming substations). However, the main differences between the two will be discussed later in the research document.

2.6 Economic Output-Energy Relationship

2.6.1 Early Findings by Moroney and MSV (1989 - 1990).

Within the range of selected variables impacting the utilisation of electrical networks, the output-energy relationship with alternative measures of output and energy has been the scope within a growing field of energy economics. The question asked is whether the economic output-energy relationship follows the traditional law of diminishing returns of production means. Initial findings of Moreney (1990) have indicated that "the wealthiest of countries exhibit a sharply diminishing real income response with respect to higher energy use" [2.9.6 p3]. Subsequently, evidence has indicated non-diminishing returns to energy per capita which implies that output could grow with energy input at a non-decreasing rate with all other factors remaining unchanged.

The period under consideration was between and including 1978 to 1980. The three functional forms considered by MSV included linear, semi-log and double log while Moroney included the semi-log quadratic function. Further limitations in their studies include:

- They studied the output-energy relationship with a single input energy model with GNP and calculated at market exchange rates (GNP_{MER}) and not GDP at purchasing power parity (GDP_{PPP}). The later measure (GDP_{PPP}) provides a more accurate result of the output for economies that do not have a free market for foreign currency exchange.
- Traditional fuels such as fuelwood and agricultural residues were ignored by Moroney and MSV, as they only used commercial consumption as a measure of energy input in their model.

2.6.2 Developments by Shrestha (2000).

Shrestha extended the scope of the previous findings by examining the effects on output-energy relationship by using alternative measures of output. The output can be expressed in various terms with the question being: What is the significance of the change in the unit of output - GNP calculated at market exchange rates (GNP_{MER}) and GDP at purchasing parities (GDP_{PPP}). Furthermore it included traditional fuels in energy consumption and the scope of the study covered recent data (1988 – 1980) from a cross-section of 41 countries. These findings were to be compared to the previous findings of Moroney and MSV.

2.6.3 Model Applied by Shrestha.

The linear model; $Y = \alpha + \beta X$ (where Y is GNP per capita and X the energy consumption per capita), revealed as MSV neither increasing or decreasing returns to energy per capita. This is due to $Y'' \equiv d^2Y/dX^2 = 0$. The semi-logarithmic model; $Y = e^{\alpha + \beta X}$ only allows increasing returns due to $Y'' = \beta^2 Y > 0$. Whereas the double-logarithmic model; $Y = AX^{\beta}$ allowed either increasing, constant, or decreasing returns to energy per capita. As in the MSV study the general Box-Cox model ; $Y_I^{(\lambda 1)} = \alpha + \beta X_i^{(\lambda 2)} + \varepsilon_I$ (also known as the 'unrestricted' model) was applied to identify the maximum likelihood power transformations of the response variable Y. Where, $Y_I^{(\lambda 1)}$

$\equiv (Y_i^{\lambda 1} - 1)/\lambda_1$ and $X_i^{(\lambda 2)} \equiv (X_i^{\lambda 2} - 1)/\lambda_2$. To statistically test the suitability of a restricted model the following expression was applied.

$$2[L(\lambda_1, \lambda_2)_{UR} - L(\lambda_1, \lambda_2)_R] \sim \chi_2^{2}.$$

Where $L(\lambda_1, \lambda_2)_{UR}$ and $L(\lambda_1, \lambda_2)_R$ represent the maximum likelihood ratio values of both the unrestricted and restricted models.

The results of maximum likelihood solution are tabulated in *Tables 2.4 to 2.6* and finally depicted graphically in *Figure 2.5: Output per Capita vs. Energy Consumption per Capita*

Table 2.4: Estimates of parameters of output-energy relationship with GNP_{MER} as the output measure

Model	α	β	λ_1	λ_2	R^2	$(R^2)^b$	$L(\lambda_1, \lambda_2)$	χ_2^2
1988								
Optimal	0,721	0,959	0,059	0,088	0,880	*0,880*	-364,381	0
	(3,760)	(0,860)	(0,096)	(0,128)				
Double-log	0,033	1,120	0	0	0,879	*0,879*	-364,765	0,768
	(0,492)	(0,066)						
Semi-log	7,070	0,00044	0	1	0,668	*0,668*	-385,518	42,274
	(0,181)	(0,00005)						
Linear	1050,0	2,580	1	1	0,696	*0,722*	-401,0	73,238
	(987,0)	(0,273)						
1989								
Optimal	1,40	0,769	0,024	0,081	0,860	*0,861*	-372,064	0
	(3,360)	(0,778)	(0,100)	(0,158)				
Double-log	-0,054	1,140	0	0	0,859	*0,859*	-372,325	0,522
	(0,549)	(0,074)						
Semi-log	7,110	0,00045	0	1	0,659	*0,659*	-390,395	36,662
	(0,190)	(0,000052)						
Linear	1180,0	2,80	1	1	0,658	*0,681*	-408,0	71,872
	(1190,0)	(0,323)						
1990								
Optimal	0,903	0,901	0,041	0,081	0,858	*0,858*	-376,309	0
	(3,920)	(0,901)	(0,104)	(0,160)				
Double-log	-0,115	1,150	0	0	0,857	*0,857*	-376,576	0,534
	(0,564)	(0,075)						
Semi-log	7,190	0,00045	0	1	0,651	*0,651*	-394,870	37,122
	(0,194)	(0,000053)						
Linear	1360,0	3,030	1	1	0,651	*0,662*	-412,0	71,382
	(1300,00)	(0,355)						

[a] Figures inside parentheses represent standard errors of the estimated parameters.
[b] These figures represent the values of R^2 that are comparable to those of double and semi-log models (i.e. with log Y as the dependant variable).
[c] 'Optimal' here refers to the Box-Cox model.

Table 2.5: Estimates of parameters of output-energy relationship with GDP_{MER} as the output measure[a]

Model	α	β	λ_1	λ_2	**R^2**	**$(R^2)^b$**	$L(\lambda_1, \lambda_2)$	χ_2^2
1988								
Optimal	-1,050	1,700	0,123	0,055	0,950	*0,950*	-258,463	0
	(5,190)	(1,290)	(0,128)	(0,129)				
Double-log	1,320	0,934	0	0	0,951	*0,951*	-259,244	1,562
	(0,297)	(0,039)						
Semi-log	7,120	0,00038	0	1	0,714	*0,714*	-286,597	56,268
	(0,180)	(0,000044)						
Linear	1030,0	1,830	1	1	0,853	*0,869*	-280,0	43,074
	(575,0)	(0,141)						
1989								
Optimal	0,097	1,380	0,081	0,034	0,937	*0,939*	-263,039	0
	(4,450)	(1,230)	(0,132)	(0,148)				
Double-log	1,370	0,925	0	0	0,939	*0,939*	-263,340	0,602
	(0,333)	(0,044)						
Semi-log	7,120	0,00038	0	1	0,716	*0,716*	-287,182	48,286
	(0,182)	(0,000044)						
Linear	1040	1,820	1	1	0,825	*0,860*	-283,0	39,922
	(646,0)	(0,156)						
1990								
Optimal	0,013	1,400	0,084	0,036	0,933	*0,935*	-264,484	0
	(4,550)	(1,240)	(0,122)	(0,144)				
Double-log	1,350	0,930	0	0	0,935	*0,935*	-264,793	0,618
	(0,347)	(0,046)						
Semi-log	7,150	0,00037	0	1	0,706	*0,706*	-288,114	47,26
	(0,184)	(0,000044)						
Linear	1130	1,82	1	1	0,810	*0,847*	-285,0	41,032
	(678,0)	(0,164)						

[a] Figures inside parentheses represent standard errors of the estimated parameters.
[b] These figures represent the values of R^2 that are comparable to those of double and semi-log models (i.e. with log Y as the dependant variable).
[c] 'Optimal' here refers to the Box-Cox model.

Table 2.6: Estimates of parameters of output-energy relationship with GDP_{PPP} as the output measure[a]

Model	α	β	λ_1	λ_2	R^2	$(R^2)^b$	$L(\lambda_1, \lambda_2)$	χ_2^2
1988								
Optimal[c]	7.140	0.766	0.133	0.130	0.897	*0.896*	-357.324	0
	(4.710)	(1.090)	(0.209)	(0.135)				
Double-log	4.250	0.614	0	0	0.894	*0.894*	-358.027	1.404
	(0.250)	(0.034)						
Semi-log	8.10	0.00025	0	1	0.703	*0.703*	-379.233	43.816
	(0.093)	(0.000026)						
Linear	3140.0	1.880	1	1	0.793	*0.828*	-377.0	39.350
	(554.0)	(0.154)						
1989								
Optimal[c]	9.560	0.749	0.185	0.197	0.893	*0.891*	-361.009	0
	(7.770)	(0.993)	((0.2)	(0.164)				
Double-log	4.240	0.620	0	0	0.886	*0.886*	-362.478	2.938
	(0.266)	(0.036)						
Semi-log	8.120	0.00025	0	1	0.723	*0.723*	-380.635	39.252
	(0.092)	(0.000025)						
Linear	3090.0	2.040	1	1	0.818	*0.843*	-378.0	33.982
	(566.0)	(0.154)						
1990								
Optimal[c]	6.260	1.380	0.190	0.130	0.865	*0.861*	-371.792	0
	(7.070)	(2.0)	(0.226)	(0.172)				
Double-log	4.040	0.658	0	0	0.862	*0.862*	-372.632	1.680
	(0.315)	(0.042)						
Semi-log	8.190	0.00026	0	1	0.665	*0.665*	-390.780	37.976
	(0.108)	(0.000029)						
Linear	3690.0	2.190	1	1	0.735	*0.861*	-390.0	36.416
	(775.0)	(0.211)						

[a] Figures inside parentheses represent standard errors of the estimated parameters.
[b] These figures represent the values of R^2 that are comparable to those of double and semi-log models (i.e. with log Y as the dependant variable).
[c] 'Optimal' here refers to the Box-Cox model.

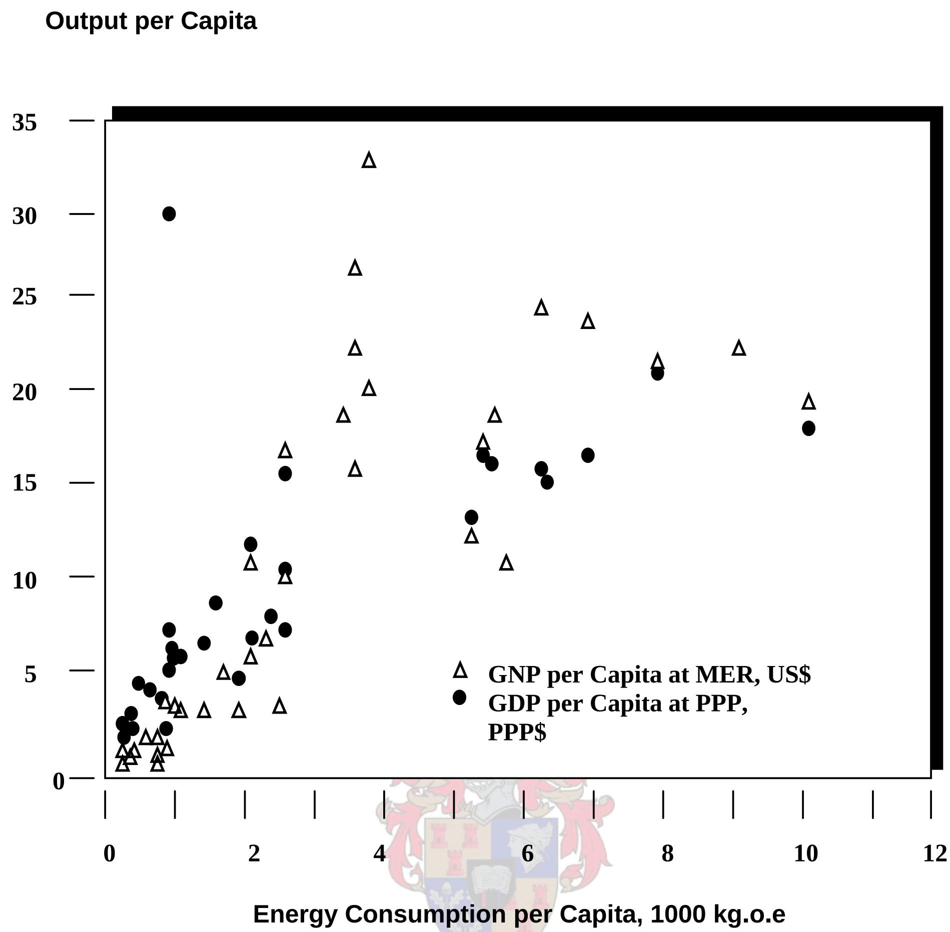


Figure 2.5: Output per Capita vs. Energy Consumption per Capita

2.9.4 Findings of Shrestha.

Shrestha concluded by rejecting MSV's hypothesis of non-diminishing returns to energy per capita. The empirical relationship between output per capita and energy is not "invariant" with respect to the type of output measure used. Despite the hypothesis of non-diminishing per capita output returns to energy use per capita is rejected when (GDP_{PPP}) is applied as the output measure, it is accepted when (GNP_{MER}) is applied as the output measure. The above result is consistent whether traditional fuels were included in energy consumption.

2.9.5 Conclusion.

Revisiting the initially identified variable regarding international output-energy consumption per capita. One can conclusively state that this measure does not contribute significantly to the derivation of an electrical transmission network utilisation index for the following reasons:

- The traditional and proved law of diminishing returns of production means is ambiguous regarding the relationship output per capita and energy. As proved by Shrestha the adherance to the law is dependant on the choice of output measure (GDP_{PPP} or GNP_{MER}).
- The output-energy relationship is not different or indifferent, whether traditional or commercial energy consumption is applied. This fact disproves any suggestion that the law of diminishing returns is different in either developing or industrialised countries.

From the above the researcher has applied GDP per capita in the exogenous variable. This issue is addressed further in *Chapter 6: Primary Variable "Exogenous" Discussion.*

2.7 CO_2 Emissions

Between 1990 and 1998 total EU carbon dioxide emissions stabilised, mainly due to reductions in Germany, the United Kingdom, and Luxembourg. Carbon dioxide emissions are projected to increase by 3% to 4% by 2010 compared to 1990 levels. The largest rise is expected to occur in the transport sector with a projected increase of 25% from 1990 levels, assuming implementation of the EU strategy to reduce emissions from cars.

Carbon dioxide is the most significant greenhouse gas; it contributes about 80% of total EU greenhouse gas emissions. Total EU emissions in 1998 were similar to those in 1990. Emissions fell between 1990 and 1994, mainly because of relatively slow economic growth, increases in energy efficiency, economic restructuring of the new Länder in Germany and the switch from coal to natural gas, mainly in the United Kingdom. Emissions then increased by 3% between 1994 and 1998.

There is a growing trend in the growth of per capita GDP and CO_2 emissions. This is illustrated in *Figure 2.6: Growth of per Capita GDP and CO_2 Emissions*.

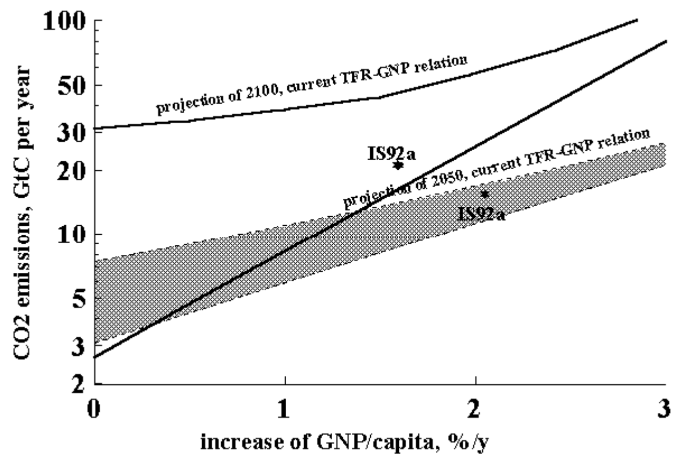


Figure 2.6: Growth of per Capita GDP and CO_2 Emissions.

This subject is discussed in more detail in *Chapter 6: Primary Variable "Exogenous" Under Discussion.*

Chapter 3

DATA COLLECTION, PROCESSING & EVALUATION METHODOLOGY

Chapter Objective

This chapter's objective is to provide a background to the data collection, processing and statistical evaluation methodology of this research study. Two processes for construct validation are reviewed and considered for the suitability for this research. Furthermore, the statistical process of applying both factor analysis and principal component analysis is discussed in detail.

3.1 Overview

Figure 3.1 Chapter 3 Overview represents an overall insight into the chapter. Various statistical researchers' studies and their proposals were reviewed. Stemming from their observations the researcher has chosen factor analysis as the final appropriate research analytical tool. More specifically, the findings of J. Stevens [3.1] suggest that exploratory factor analysis is relevant. Validation studies were reviewed with the construct validation study being the proposed method. However, although the construct validation process of Kivlighan and Wampold [3.2] deemed appropriate, a modification to the process was introduced from the suggestions of Johnson and Wichern (p517) [3.3]. The accuracy of the analytical software XLSTATS was verified against STATISTICA.

The complexity of analysing the relations among a set of random research variables observed includes the accountability for determining inter-correlations and postulating a set common factor. Gorsuch (1983) reminded researchers that they "are united in a common goal in that they seek to summarise data so that the empirical relationship can be grasped by the human mind." (p2) [3.4]. One statistical means of achieving the former is by applying the process of factor analysis. The purpose of factor analysis "is to summarize the interrelationships among the variables in a concise but accurate manner as to aid in conceptualization.” (p2) [3.4].

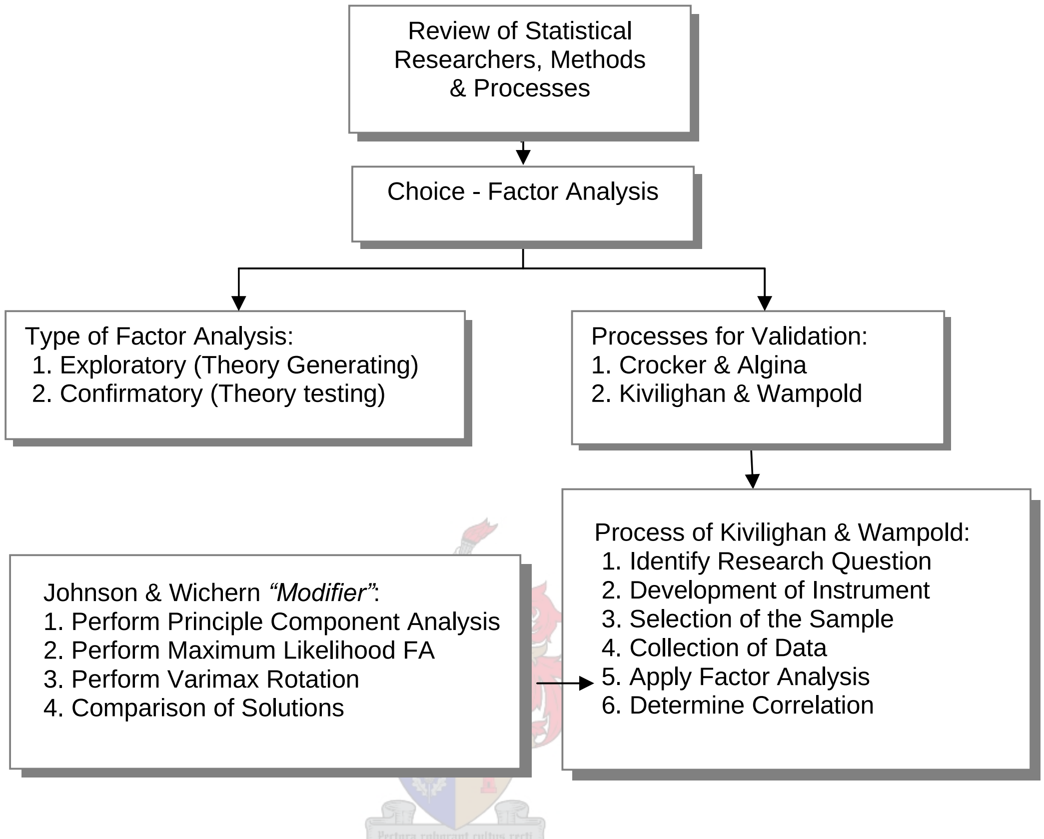


Figure 3.1: Chapter 3 Overview

One statistical means of achieving the former is by applying the process of factor analysis. The purpose of factor analysis “is to summarize the interrelationships among the variables in a concise but accurate manner as to aid in conceptualization.” (p2) [3.4]. Within this research context, it is the intent of this statistical process to summarise the interrelationships among the three primary research variables (U, R, & E) in order to conceptualise the derived composite utilisation index.

Reviewing the studies of statisticians such as Kerlinger (1979) [3.5], Cureton and D’Agostino (1983) [3.6], Bryman and Cramer (1990) [3.7], and Reyment and Jorskog (1993) [3.8], each of their definitions of factor analysis communicates a common message of reducing the number of variables into smaller sets of factors which effectively reduce large amounts of data into manageable form and dimension. Likewise, the former definitions apply to the reduction of the collected performance data relating to this particular study.

The initial question to be asked is, whether the validity of factor analysis is within the scope of this research project? This can be addressed by referring to Cronbach (1971) [3.6] who suggested that the validation was a process by which evidence is collected that supports the types of inferences derived from test scores. Three types of validation studies were discussed by Crocker and Algina that included content, criterion related and construct validity.

Reviewing the former's studies and those of Shepard (1993) [3.8], and Anastasi (1986) [3.8], the researcher has adopted to construct the factorial validity based on Heppner, Kivlighan and Wampold (1992) [3.2]. This construct validity is "the degree to which the measured variables used in the study represent the hypothesized constructs." (p.47) [3.2]. Cronbach confirms that "one validates, not a test, but an interpretation of data arising from a specified procedure".

Two processes for construct validation were reviewed and considered for the suitability for this research. These included the suggestions by Crocker and Algina, and Kivlighan and Wampold [3.10]. The latter process was chosen for this research. This process includes the following: identifying the specific research question to be addressed, the development of an instrument constituting the variables specified, the selection of the sample, collection of the data, applying factor analysis to identify dimensions of a set of variables and the factors, and finally determining if the factors are correlated. The subsequent sections within Chapter 3 will be based and compiled on the previously described process.

Having identified factor analysis as the research analytical tool, it would be theoretically appropriate to determine what type of factor analysis is most relevant to this study. The options are either *exploratory* factor analysis (EFA) or *confirmatory* factor analysis (CFA). Stevens (1996) [3.1] summarised the main differences between the two types in *Table 3.1: Exploratory versus Confirmatory Theory of J. Stevens.*

Table 3.1: Exploratory versus Confirmatory Theory of J. Stevens

EXPLORATORY (THEORY GENERATING)	**CONFIRMATORY (THEORY TESTING)**
Heuristic – weak literature • *Determine the number of factors.* • *Determine whether the factors are correlated or uncorrelated.* • *Variables free to load on all factors.*	Strong theory and/or strong empirical base • *Number of factors fixed a priori.* • *Factors fixed a priori as correlated or uncorrelated.* • *Variables fixed to load on a specific factor or factors.*

As this research is based on more of a *theory-generating*, rather than a *theory-testing* procedure, it is considered justified in assuming the exploratory factor analysis is the applicable approach. This assumption can be further substantiated by the lack, or more accurately the scarcity, of a strong empirical base. It must, however be acknowledged that the data obtained in this research is based on sound engineering performance measuring aides which have been the topic of discussion at international forums such as IEEE, IEE and Cigré. Such an example is the performance measurement of "System Minutes" which has been defined in Chapter 1. The economic measurements under the exogenous variable such as "per Capita Energy Consumption", "Primary Energy Consumption", Commercial Energy Consumption" and "Gross Domestic Product" have been constituted at similar international proceedings.

3.2 Identifying the Specific Research Question

The primary question regarding the application of factor analysis is whether the data is consistent within a prescribed structure. Factor analysis is a statistical method to determine the underlying unobservable factor(s) which explain(s) the correlation structure among the observed variables.

This is placed into context by …

"it assumes the existence of a system of underlying factors and a system of observed variables. There is a certain correspondence between these two systems and factor analysis "exploits" this correspondence to arrive at conclusions about the factors." (Kim, 1986, p.8) [3.10].

The specific research question relates to the minimum number of underlying hypothetical factors that represent a larger number of variables. In this study there are basically three primary variables: transmission network utilisation, transmission reliability measures and exogenous measures relating to socio-economic parameters. The question can be answered by firstly identifying the minimum number of hypothetical factors in each of these groups of variables. Finally the question must be answered as to whether these identified factors are related.

The success of factor analysis application can be attributed to the number of pm factor loadings. Where p is the number of samples (in this case the number of electric utilities), and m is the number of variables. When m is small relative to p factor analysis is most useful [3.3]. In each of the three groupings the variables (p) have been restricted to 4 and the number of factors (m) to 1. The number of observations (n) considered was 22 electric utilities.

Certain limitations were imposed on the statistical analysis. These imposed limitations proposed to enhance the filtering of multivariables in order to retain credit worthiness of the final derived utilisation index. Each common factor of the variable groupings (*U, R, & E*) was limited to one in each group. These are explained in detail in Chapter 4, 5 and 6. Such limitations resulted in the prevention of a verimax rotation as the factor loadings were limited to 1 in each factor. This limitation is based on ½ $[(p\text{-}m)^2 - p - m]$ which must yield a positive value [3.3 (p 499)]. In each of the variable groupings 1 factor loading was considered.

3.2.1 Transmission Network Utilisation (*U*)

The common factor of all four secondary variables within this group is ***utilization*** and consists of the following:

- Maximum Demand (MW)/Number of Installed Transformers (km) [U_1].
- Maximum Demand (MW)/Length of Transmission Lines (km) [U_2].
- Energy Losses (MWh)/Total Energy (MWh) [U_3].
- Energy Losses (MWh)/Length of Transmission Lines ((km) [U_4].

The above variables can be represented in the form.

$$U_1 = \lambda_1.f + u_1 \quad (3.1)$$

$$U_2 = \lambda_2.f + u_2 \quad (3.2)$$

$$U_3 = \lambda_3.f + u_3 \quad (3.3)$$

$$U_4 = \lambda_4.f + u_4 \quad (3.4)$$

Where: λ_1, λ_2, λ_3 and λ_4 are "factor loadings". Random disturbances are represented by u_1, u_2, u_3 and u_4.

3.2.2 Transmission Network Reliability (*R*)

The common factor of all four secondary variables within this group is ***reliability*** and consists of the following:

- System minutes / maximum demand (MW) [R_1].
- System minutes / total MWh [R_2] .
- Number of interruptions / maximum demand (MW) [R_3].
- Number of interruptions / total MWh [R_4].

As in section 3.2.2, equations (3.1, 3.2, 3.3 and 3.4), the factor loadings and random disturbances can be represented by:

R_1 = $\lambda_1.f + u_1$ ………………………… (3.5)

R_2 = $\lambda_2.f + u_2$ ………………………… (3.6)

R_3 = $\lambda_3.f + u_3$ ………………………… (3.7)

R_4 = $\lambda_4.f + u_4$ ………………………… (3.8)

3.2.3 Exogenous Influences (*E*)

The common factor of all four variables within this group is ***exogenous influences*** and consists of the following variables:

- Per capita energy consumption (million tons / capita) [E_1].
- CO_2 emissions per capita (million tons / capita) [E_2].
- Gross Domestic Product / capita ($\$_{US}$ / capita) [E_3].

As in section 3.2.2, equations (3.1, 3.2, 3.3 and 3.4) can be represented by:

E_1 = $\lambda_1.f + u_1$ ………………………… (3.9)

E_2 = $\lambda_2.f + u_2$ ………………………… (3.10)

E_3 = $\lambda_3.f + u_3$ ………………………… (3.11)

Where: $\lambda_1, \lambda_2, \lambda_3$ and λ_4 are "factor loadings". Random disturbances are represented by u_1, u_2, u_3 and u_4. The random disturbances will not be included in the final derived equation due to the variances in the original data.

In each of *U, R, and E* the researcher will compute the factor scores of the single factor extracted, and denote these as U_f, R_f, *and* E_f. The correlation among these factor scores will then be computed and interpreted. An expected affirmative research result would be the graphically representation of a 3-dimensional transmission utilisation performance measurement aid as illustrated in *Figure 3.2: Transmission Network*

Utilisation Index. The 3-dimensional graph will represent the dominant secondary variable in each of the three primary transmission utilisation variables (*U, R, & E*). It is anticipated that electric utilities will be able to position themselves according to this 3-dimension graph and accordingly strategise transmission network expansion within the considerations of utilisation, reliability and exogenous (social economic) factors.

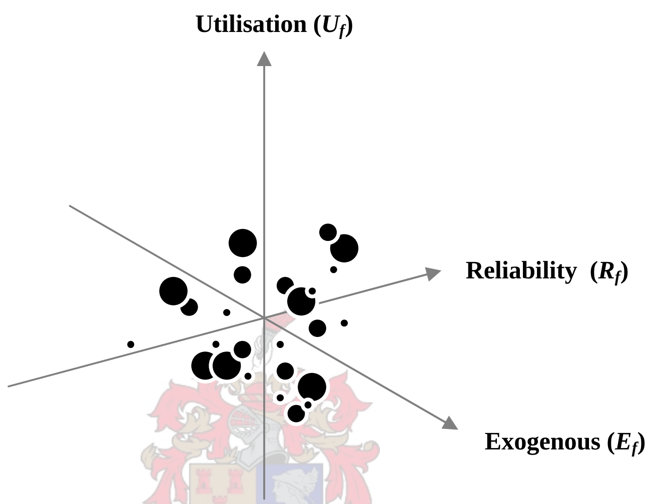


Figure 3.2: Transmission Network Utilisation Index

3.3 Selection of the Sample

The sample of cases differs among methodologists resulting in no definite scientific answer to the number of cases required for the research study. However Bryant & Yarnold endorsed both: the subjects-to-variables ratio (STV) of at least 5, and the Rule of 200 (Bryant & Yarnold, 1995) [3.7]. The Rule of 200 stipulates that there should be at least 200 cases, regardless of the subjects-to-variables ratio.

In this research study most technical data was sourced from the National Grid Company (Comparison of International Transmission Utilities) which consisted of 21 utilities. The collection of data extended over a period of 7 years – from 1992 to 1999. The researcher been one of the active participants and accountable for the data presented during that period from Eskom Transmission. An example of the data collected during this exercise is found in Appendix 1: Example of Electricity Utility Data. Not all utilities responded to all of the questions. Certain utilities excluded themselves from participating during the full duration of the study. Attempts were made to obtain data from developing countries but unfortunately no data was received. This was attributed to language constraints and the assumed possibility that the countries concerned were not fortunate to dedicate skilled resources to the project. Another constraint was the fact that numerous electricity utilities have transformed from para-statal to privatised profit generating entities, operating under the scrutiny of national electricity regulators. This has had the effect that electricity utilities are less cooperative in revealing their “engine room” details. Their overall sustainability, from a shareholders point of view, is more dependent on financial final accounts – income statement and balance sheet. Furthermore comparative studies or benchmarking is a fast growing commercial industry which excludes non-participating utilities from obtaining data as freely as in the past. Exogenous data was obtained from the United Nations Statistical Division Common Database. The Energy Statistics Division of the IEA which collects, processes and releases data and information on energy products, transformation, consumption, prices and taxes as well as on gaseous emissions. It must be noted that participating utilities were subjected to confidentiality constraints. Therefore although the data presented is factual, the relevant utilities are not named or referred to. This has also resulted in exogenous data not being identified to a particular country as to prevent the identification of single utilities to a specific country or geographical area.

3.4 Application of Factor Analysis

Johnson & Wichern suggests a 5-step "reasonable option" as a strategy in the application of factor analysis (p. 517) [3.3]. The researcher has adopted this option with the exclusion of steps 4 & 5. The steps suggested are:

3.4.1 Perform a principal component factor analysis. During this process the plot scores may be used to identify suspicious observations. Finally a varimax rotation should be applied.

3.4.2 Perform a maximum likelihood factor analysis which would include a varimax rotation.

3.4.3 Compare the solutions obtained from both principal component analysis and maximum likelihood factor analysis.

3.4.4 Repeat the first 3 steps for other numbers of common factors m.

3.4.5 Large data set should be split in half and a factor analysis performed on each half section – *this was not deemed necessary as this research collected data does not represent a large data set.*

The data relating to the above (3.4.1 & 3.4.2) was processed by means of XL-STATS Version 6.19 & XL-STATS 3D Plot 4. The analytical software XL-STATS was compared against STATISTICA and the results proved very similar. This verified the accuracy of the processed data. Initially principal component analysis (PCA) was applied. Each common factor (*U, R, & E*) was analysed separately and 1 factor loading associated with the 4 non-trivial eigenvalues chosen from each common factor. During this process Pearson correlation coefficient was applied.

3.4.1 <u>Principal Component Analysis (PCA)</u>. [12 (p.23-52)], [13 (p.388-426]

Principal component analysis was used to summarize the structure of data described by the secondary quantitative variables, while obtaining the uncorrelated factors between them. These factors may be used as new variables which allow the researcher to:

- avoid multicolinearity in multiple regression or in discriminant analysis,

- perform cluster analysis while considering only essential information, i.e. by keeping the primary factors only.

Principal component analysis (PCA) expresses a set of variables as a set of linear combinations of factors that are not correlated between them; these factors represent an increasingly small fraction of the variability of the data. This method allows one to represent the original data (observations and variables) with fewer dimensions than the original, while keeping data loss to a minimum. Representing the data in a limited number of dimensions greatly facilitates analysis.

The linear combinations of the variables are represented as:

$$\text{Utilisation } (U_f) = a_1U_1 + a_2U_2 + a_3U_3 + a_4U_4 \quad \ldots \quad (3.12)$$

$$\text{Reliability } (R_f) = a_1R_1 + a_2R_2 + a_3R_3 + a_4R_4 \quad \ldots \quad (3.13)$$

$$\text{Exogenous } (E_f) = a_1E_1 + a_2E_2 + a_3E_3 \quad \ldots \quad (3.14)$$

Subject to the constraint that …

$$a_1^2 + a_2^2 + a_3^4 + a_4^2 = 1 \quad \ldots \quad (3.15)$$

PCA differs from factor analysis in that it creates a set of factors that have no correlation to one another; this corresponds to the special case where all communalities are equal to 1 (null specific variance).

3.4.2 Factor Analysis. [14 (p. 246-250)], [15 (p. 90-143)] & [16 (p. 7-24)]

The purpose of factor analysis is to describe a set of variables using a linear combination of common underlying factors, and a variable representing the specific part of the original variables. The variance of an original variable may be broken down into a part shared with other variables (explained by the factors) called the communality of the variable, and a specific part called the specific variance. Among the various methods available, XLSTAT uses the principal factor method applied iteratively. The communality of each variable is initialized so that a variable with a very low correlation to the others has a low communality and therefore a high specific variance. By default, XLSTAT initializes the communalities using the square of the multiple correlation with the other variables. If this method cannot be used, or if it is too time-consuming, XLSTAT uses the square of the highest simple correlation with the other variables. After the communalities are initialized, the factor loadings are estimated by iteratively using the principal factor method until the values stabilize or until the maximum number of iterations is reached.

The findings of Bartlett [3.12] and the chi-square approximation are then applied by the programme XLSTATS. The following represent the statistical values generated. A decision was taken to reject the null hypothesis of significant correlation between variables at a level of alpha = 0.05. The value 0.05 is a standard and common statistical accuracy level. The researcher considered it unnecessary to deviate from this standard. Eigenvalues, their variance and accumulative variance, and the eigenvectors were determined from which the factor loadings were derived.

The application of the varimax rotation is to simplify the interpretation of factors by minimizing the number of variables that contribute significantly to each factor. The objective of the orthogonal varimax rotation is to identify a factorial structure where for each factor, a few variables have strong contributions and the other factors have very weak contributions. This objective is obtained by maximizing, for a given factor, the variance of the squares of the contributions among the variables, with the constraint that the variance of each variable must remain unchanged. However in this research study, a varimax rotation could not be performed as the factor loadings were limited to 1 in each factor. This limitation is based on $\frac{1}{2}[(p-m)^2 – p – m]$ must be positive [3.3 (p 499)].

Chapter 4

PRIMARY VARIABLE "UTILISATION" UNDER DISCUSSION

Chapter Objective

This chapter's objective is to provide a background to the new challenges facing electricity utilities specific to network utilisation in the face of increasing competition, regulation and privatization. The chapter's objective is to provide an in depth discussion of the "utilisation" primary variable (U_f) and its four secondary variables (U_1, U_2, U_3, U_4). Input data is screened for outliers. Thereafter factor analysis and principal component analysis are applied to formulate the final equation for U_f. The application of these findings are discussed in detail in Chapter 7: Discussion Emanating from the Research.

The following issues are addressed under the discussion: Addressing complexities in transmission network utilisation, transmission investment at a slower pace than that of generation, rate and magnitude of installed transmission transfer capability, stranded costs in transmission network expansion or refurbishment, addressing complexities in transmission network utilisation, system operating constraints, and utilisation and the changing credit risk criteria. The chapter processes the available data and presents the final linear equation for the primary variable utilisation.

4.1 Chapter Overview

The concept of transmission network utilisation contains opposing objectives for different stakeholders. Firstly, as an asset owner and investor the objective is to exploit the transmission network by making the assets "sweat" or "stretch" in the short term. In modern times this can be considered a mercenary approach as both investor and top management (positions that is) are often short-lived – 3 years is considered an average term for top management, and investors ride the crest of the changing value of paper shares, exploiting economic conditions. Secondly, from a grid operator and a customer viewpoint, they would be reassured in knowing that there is spare capacity in the transmission network to accommodate the most highly probable contingencies. The balance between these two objectives is largely influenced by the economic laws of supply and demand. New engineering technologies and operational practices can contribute to the supply component of electricity by influencing the cost. The US electricity network is reviewed and the growth in demand and transmission line loading relief requests are noted as early warning indicators of transmission utilsation constraints. Rate and magnitude of installed transmission transfer capacity has changed over the years. The chapter reviews the trend of this topic and discusses the explanation thereof. The European electricity market is also referred to and specifically the cross-regional interface between electric utilities.

Benefit of spare capacity is discussed and the obvious system operating constraints. Traditional accounting concepts and investment criteria are also challenged within the modern privatised electric utility and credit risk criteria are considered growing considerations in investment decision making. *Utilisation* performance indices are chosen and the raw data filtered to eliminate outliers. The statistical process was followed as described in *Chapter 3: Data Collection, Processing & Evaluation Methodology (p3.8).* The findings are compared, from both the principal component analysis and the factor analysis statistical process. The final linear equation for the primary variable *utilisation* is derived from the eigenvalues and factor loadings.

4.2 Current transmission transfer capacity

Defining transmission capacity is a challenging task due to a number of dependent factors relating to the transmission network. Under ideal conditions, the transfer of energy is limited by the ability of the overhead lines and plant to withstand the heat generated by losses (or the thermal limit). Transfer is also restricted at lower transfer levels due to voltage or stability concerns as well as the need to maintain transmission network reserves for contingencies. Defining the required amount of transmission capacity, referred to as adequacy, is even more challenging. Adequacy is a time-dependent concept and is a function of the locations and magnitudes of generation and demand, the current configuration of the transmission grid, and possible contingencies that would affect energy transfer and the transmission lines in service. Transmission planners make use of data and projections which provide useful insights on recent and likely future trends in transmission capacity.

Because the carrying capacity of transmission lines (in MW) increases with higher voltage levels, summing the length of transmission lines represents a misleading picture of the actual capacity of the system. For example, a 765-kV line can carry almost as much power as ten 275-kV lines. Weighting the length of transmission lines according to their thermal limits presents a more accurate measure of transmission capacity in GW-miles. Thermal limits are the real limiting factor, and the basis for a line's rating. Some studies show most transmission lines can carry 5% to 20% more power than they do under present limitations [4.1]. The Public Service Company of New Mexico (PNM, Albuquerque, New Mexico, U.S.) found that long-used assumptions for conductor-rating calculations are generally conservative. In many cases, PNM justified increasing the assumed wind speed from the traditional 2 ft/sec value. This alone has a significant impact on circuit ampacity as controlled by conductor temperature and PNM increased the ratings of several 115-kV circuits by 15% at 100°C (212°F). However, this design practice is not recommended unless additional risk assessments are done.

Utilities must maintain a safe clearance between energized conductors and the ground, trees, vehicles and other objects directly below the line, as specified in statutory regulations.

Of relevance to this research are the following findings of Dr. Eric Hirst of Tennessee [4.2]. In August 2000 he revealed the simple sum of transmission circuit miles and the weighted measure of GW-miles are highly correlated (r = 0.99) for the two-decade period from 1978 through 1998. This finding suggests that the mix of transmission-line voltages was stable during this period. U.S. transmission capacity increased slowly from 1978 to 1998, from 89 to 132 thousand GW-miles, or from 107 to 149 thousand miles. *Table 4.1: Decline in Transmission Capacity in the US* illustrates the continuing problem regarding the decline in transmission capacity.

Table 4.1: Decline in Transmission Capacity in the US.

Decline in Transmission Capacity by Region

NERC Region[a]	Area Served	Transmission Capacity (MW-miles/MW peak demand) 1998	2008	Percentage Change 1989–1998	1998–2008
ECAR	Midwest	201	176	–19.1	–12.7
ERCOT	Texas	116	108	–24.5	–6.4
FRCC	Florida	117	107	–17.9	–8.4
MAAC	Mid-Atlantic	110	94	–11.7	–14.6
MAIN	Illinois and Wisconsin	107	96	–15.7	–10.0
MAPP	Northern Plains	320	265	–14.0	–17.1
NPCC	Northeast	116	101	–5.2	–12.6
SERC	Southeast	172	140	–14.6	–18.8
SPP	Kansas and Oklahoma	134	128	–33.2	–4.5
WSCC	West	411	377	–15.8	–8.2
Total		202	177	–16.2	–12.4

SOURCE: Hirst, Eric, "Expanding U.S. Transmission Capacity," August 2000.

[a]See the Acronyms list for the full names of the regions. A map of U.S. NERC regions may be found at http://www.nerc.com.

However, that increase was lower than the growth in peak demand, to the extent that transmission is built to serve growing loads, peak demand is an appropriate normalising factor for transmission capacity. Normalised transmission capacity (either MW-miles of transmission per MW of summer peak demand or miles of transmission per GW of summer peak demand) increased between 1978 and 1982 and then declined for the subsequent 16 years. For example, the MW-miles per MW-demand indicator *increased* by 3.5 percent per year between 1978 and 1982 and then *declined* by 1.2 percent per year between 1982 and 1998. To the extent that transmission is built to connect new generators to load centers, generating capacity is an appropriate normalizing factor for transmission capacity. Because generating capacity increased more slowly than did load during this two-decade period, the trend in transmission capacity normalized by generating capacity is less clear than when transmission capacity is normalized by peak demand. Normalized by generating capacity, transmission capacity increased at about 2 percent per year between 1978 and 1984 and then remained essentially unchanged from 1984 through 1998.

Interpreting the data and projections was not obvious. The manner in which Dr. Eric Hirst presented the data suggested a growing problem in U.S. transmission capacity. Had he plotted the data as MW of peak demand per unit of transmission capacity; one might have concluded that the electricity industry was becoming more efficient in its use of the transmission network and able to utilise more power through the existing system. The truth probably lies between the two extremes. On the one hand, technological advances in data metering, communications and computing, permit system operators to run transmission grids closer to their thermal, voltage, and stability limits. For example, system operators are using dynamic ratings of transmission equipment, based on current temperatures and wind speeds, to operate equipment closer to their physical limits. And the construction of small gas-fired generators close to load centres reduces the need for transmission network expansion or refurbishment. On the other hand, transmission congestion suggests that additional transmission capacity is needed in specific locations.

The US transmission network consists of approximately 260,000 kilometres of transmission lines of 230kV and above. Historically this network has adapted to changes in technology and customer demand. However, today the same transmission network is adjusting to changes in energy policy. Included in these changes are the following: A key measure of transmission network constraints is the number of transmission line loading relief requests which are needed to curtail transactions that cause transmission facility overloads or violations of operational security limits. Between August 1999 and 2000, transmission congestion in the US grew by more than 200%. In the first quarter of 2001, transmission congestion was already three times the level experienced during the same period in 2000. There were 153 transmission line loading requests from January to March 2001, compared to 42 for the same time period in 2000 [4.1 p14]. This is illustrated in *Figure 4.1: Transmission Line Loading Relief Requests 1999 – July 2001.* Coupled with this situation is the fact that transmission annual investments declined by approximately $125 million a year during the past twenty-five years [4.3]. The shortage of transmission transfer capacity is realised when the above facts are put into perspective with the future demand. It is estimated that during the next decade, the US electricity market will grow by 2000,000 MW (or 20%).

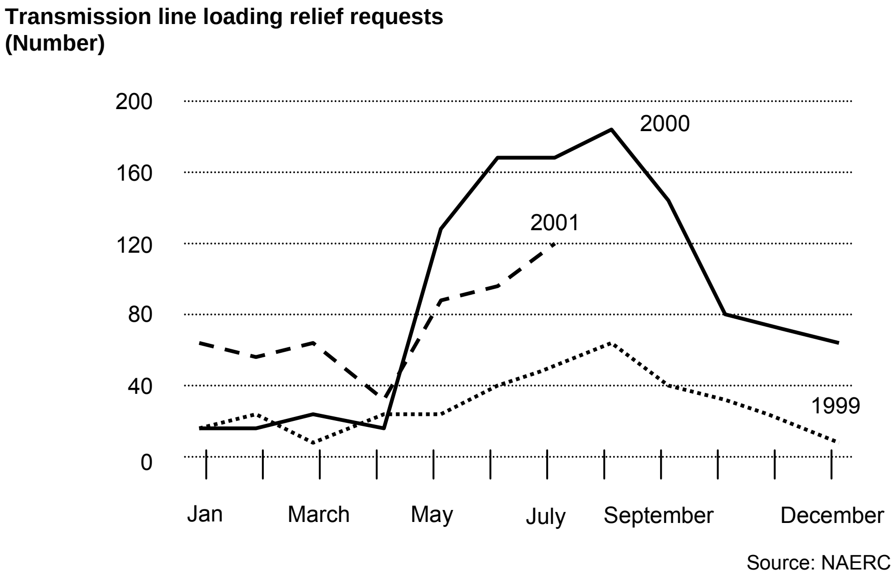


Figure 4.1: Transmission Line Loading Relief Requests 1999 – July 2001.

Existing and new generation plants are concentrated in regional areas in the close proximity of combustiable raw materials. During this period vertically integrated utilities generated, transmitted and distributed electricity. Today, retailers have the incentive to locate the least expensive wholesale electricity source. This condition has the effect of increasing the need for transmission services and in certain circumstances the lack of transmission capacity has left surplus generation capacity stranded. This surplus capacity includes part of, nearly 43,000 megawatts of electric utilities' generating assets which were sold to non-utilities or transferred to non-regulated affiliates during 2000 [4.1].

More previously discussed, transmission investment is currently at a slower pace than that of generation.

The main reasons include the following:

- difficulties in siting to build transmission lines,
- regulatory uncertainty to the tensions among the different incentives within the transmission and distribution industry [4.4 p9],

- the current rates of return on transmission investment are too low to attract the significant amount of capital needed,
- transmission expansion is capital intensive as the costs are estimated between $0.45 to $0.60 million to transfer 1000 megawatts of power (line length dependant) [4.5 p9], and
- transmission is larger than one state and spans regional markets across America.

The North American Electricity Reliability Council (NERC) states that circuit-miles of high voltage transmission will increase a total of just 4.2% over the next ten years – a rate of less than 0.5% per year [4.6 p1]. This is small if one considers that transmission represents only 11% of the national average cost of delivered power in the US [4.3 p14]. Recent studies in the US reveal that it will cost between $10 and $30 billion just to restore the transmission network to a stable condition. Thereafter it would cost $1 to $3 billion to support that transmission network [4.7 p8]. This should be weighed against the 2000 estimated congestion costs in New England, New York and in California of $800 million [4.8]. The total costs to the economy as a whole in 2001 totaled billions of dollars [4.9 p10].

Other than the above considerations, a new factor has emerged which affects the contingency planning of transmission networks. An additional threat to power distribution is the vulnerability to man-made disasters – specifically terrorism. Sufficient transmission spare transfer capacity and adequate redundancy must be built into the transmission networks to accommodate these eventualities. This is not included in the above.

4.2.1 Rate and magnitude of installed transmission transfer capability

As identified above one of the constraints to construct new transmission lines is the lack of an adequate investors return on equity (ROE). The issue is one of absence of financial incentives to transmission owners. Management concerns are that large investments will not be fully recovered. Specifically, with lifetimes of several decades and little agreement yet on the nature of transmission regulation and the pace of the jurisdictional shift from the states to FERC, utility executives are reluctant to make long-term commitments. These utility concerns are in addition to those related to the cost, time, and public opposition associated with gaining regulatory approval to build a new line.

From 1988 to 1998, the demand for electricity in the US increased by 30%, but the capacity of transmission network expanded at half that rate [4.10 p2]. New technology has allowed electricity to be transmitted over longer distances and generating technology has made smaller scale generating facilities economically feasible. A significant change has occurred in the rate and magnitude of transmission expansion to accommodate customer maximum demand forecasts. Consider *Figure 4.2: Maximum demand/Total transfer capability versus time.* The illustration assumes a proportional linear increase in customer maximum demand (MW) over time. The rate and consistency of this proportionally linear increase is rarely, if ever, representative of actual conditions. Typical world energy trends are illustrated in *Figure 4.3: World Consumption of primary energy.* This linear hypothesis is assumed for illustrative convenience. Reality indicates an increasing trend of between less than 1 to 5% growths in the maximum demand. Utilities plan their asset base to accommodate the expected customer maximum demand. Generation and transmission networks are planned, designed and constructed to allow for generation spinning reserve and transmission total transfer capacity.

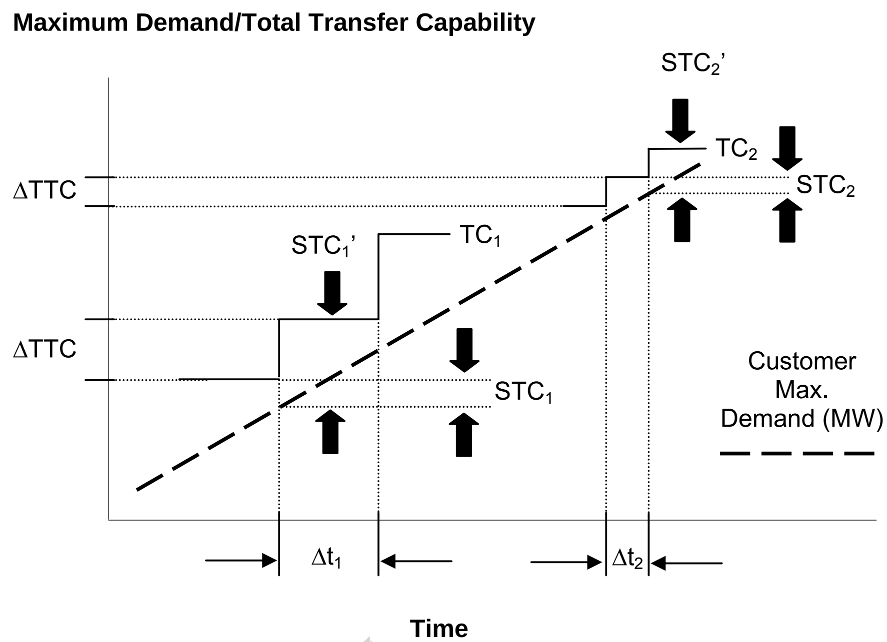
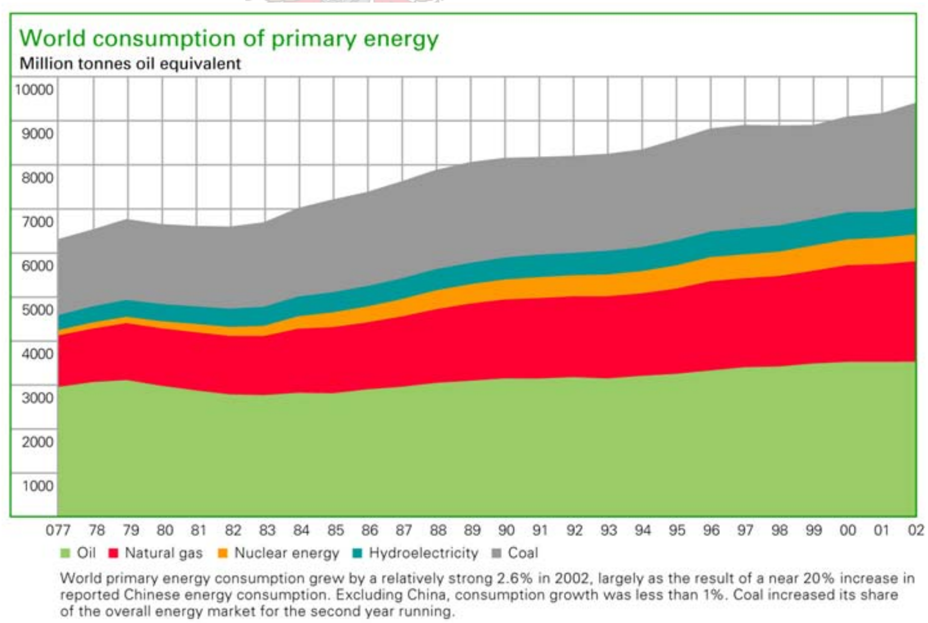


Figure 4.2: Maximum demand/Total transfer capability versus time.



BP statistical review of world energy 2003

Figure 4.3: World Consumption of primary energy.

Extensive and continuing development on available transfer capability (ATC) studies provide AC power flow solutions which incorporate the effect of reactive power flows, voltage stability and thermal loading effects of transmission lines. Furthermore, ATC studies include total transfer capability (TTC) transmission reliability margin (TRM) and capacity benefit margin (CBM) simulation. The stochastic properties of power system behaviour necessitates that the ATC be assessed from a risk analysis point of view. This will be discussed in more detail in *Chapter 5: Primary Variable Reliability Under Discussion* and incorporated under the concept of reliability and not risk assessment.

TTC_1 and TTC_2 represent total transfer capability of a utility and can be viewed from both a generation and transmission asset capability, or separately. In this instance transmission TTC is considered. Simply described, the expansion of a transmission network follows a step function as depicted above. When spare transfer capability (STC) is at the minimum allowable reserve capacity (ARC), expansion takes place which causes a step increase exceeding the STC. Of interest is the change in rate and magnitude of the transmission network expansion. Past expansion was generous and allowed for large ARC (from STC_1 to STC_1‘). This generous ARC was attributed to longer planning periods and the non-existence of market competition between utilities. Modern utilities are however operating closer to operational and stability limits due to emerging, competitive, and restructured environment. This is particular, but not limited to the U.S. electrical power industry. The following are the drivers for closer operating to limits [4.4]:

- Restructured and competitive energy markets span across many transmission boundaries which may have conflicting regulatory and market structures.
- Profit imperatives in a competitive electricity market will drive network utilisation and shortages of transmission capacity can be anticipated despite the projected load growth.
- Transmission network bottlenecks caused by the increase in cross-regional power exchanges are anticipated.

Yet another reason for the closer operating to limits, is the shorter time to react to load increases, making the planning to commissioning period shorter – compare Δt_1 to Δt_2 along TC_1 and TC_2 respectively. Traditional periods from planning to commission were from ten to twenty years.

The various techniques for generating electricity show large differences in costs. Some techniques require high capital costs with low marginal costs, while others require low capital costs with high marginal costs. Nuclear, coal-fired, and hydro power plants belong to the former group, while the latter consists of oil and gas fired power plants. The techniques with high fixed costs and low marginal costs have an economic advantage at the market for base load demand, while the peak load demand is served by the low fixed costs and high marginal costs techniques. This situation arises from the fact that during off peak moments demand and subsequent prices are relatively low. Generators with relatively low marginal costs are able to produce and send out energy under these conditions. On the other end, demand is high during peak conditions, resulting in high prices. This has the effect of making the production of high marginal costs techniques profitable. As a consequence, the number of techniques actually competing with each other is less than the total number of generation techniques that exist [4.11]. The above considers generation options to deliver customer maximum demand.

Transmission networks are faced with a further challenge. There is a continual disappearance of regional fragmentation. Consider Europe where at present there is no European electricity market. Grid constraints limit international trade in electricity. Power generated in the South of Europe cannot be supplied to end-users in the North of Europe. International trade in electricity within Europe did not take place until a few years ago. Some linkages between the national grids did exist, but they were rather limited due to concerns about the security of supply. Due to those linkages, temporary shortages in supply in one country could be overcome by means of importing from neighboring countries. In most EU countries, the liberalization of the electricity markets has been implemented in the past years. In countries like Austria, Finland, Germany, Sweden, and the UK, all end user groups are free to choose their electricity supplier. In other EU countries, such as Belgium, the Netherlands, Ireland, Italy and Spain, full opening of the market is expected to be realised in a few years [4.12]. The competition on the power market will still be hampered by remaining shortages in international transmission lines. In the Scandinavian countries, an integrated power market has existed for about 10 years. These countries established the Nordic Power Exchange, also known as Nord Pool, in 1993. The power markets in Norway, Sweden, Finland and Denmark are closely linked now. As a consequence, for instance, the hydro generators in Norway compete with nuclear power plants in Finland. The interconnections of the Scandinavian market to the other countries are, however, still very limited: not more than 1% is imported from other European countries. Other regional markets within Europe are the UK-market, the Iberian market, the Italian market and the Central European market with France, the Benelux, Germany and Austria (Morgan Stanley,2002). Within each of these markets, end-users face approximately the same electricity prices, while prices are rather different between these regions. Prices of electricity are relatively low in the Nord Pool, the UK-market, and the Central European market. The Iberian and especially the Italian markets show high electricity prices. It is expected that the regional dimension of the European electricity market will disappear in the near future. New investments in interconnection between national and regional transmission grids will improve the competition between suppliers from different parts of Europe. The ongoing process of the liberalization of European electricity markets will ultimately result in one European market.

4.2.2 Stranded costs in transmission network expansion or refurbishment.

Traditional accounting concepts such as "an ongoing concern, consistency, prudence and depreciation" are challenged by the privatization of electric utilities. The modern electric utility is presented with numerous new cost concepts and pricing options which make electricity markets different to normal businesses. Pricing options include peak load pricing and real-time based which allow customers to alter their electricity usage. However, there are additional costs to the utility for providing a modern transmission network under a regulated system. These are termed "strandable costs" and relate to the transition from a regulated to a more competitive market.

There are two definitions for strandable costs which contain subtle differences relating to the regulator. Firstly, strandable costs are defined as *those fixed and sunk costs that were imposed by the regulator in the regulated market.* And secondly, stranded costs are defined as *strandable costs that cannot be recovered via the market if the market is opened up for competition.* The first definition puts more emphasis on the role of the regulator as the supervising authority. It stresses that the regulator should *impose* the expenditures, whereas the second definition includes expenditures *approved* by the regulator [4.13]. *Table 4.2: Definition of Strandable And Stranded Costs,* summarises the recovery status of the regulators imposed sunk costs. Strandable costs become stranded when they cannot be recovered through the market after the introduction of competition.

Table 4.2: Definition of Strandable And Stranded Costs [4.4]

		SUNK COSTS IMPOSED BY THE REGULATOR?	
		Yes ↓ *Strandable*	*No* ↓ *Not Strandable*
RECOVERABLE VIA THE MARKET?	***Full recovery***	Not stranded	Not stranded
	Partial Recovery	Non-recoverable Part is stranded	Not stranded
	No recovery	Stranded	Not stranded

These costs must be considered when transmission infrastructure investment decisions are made. Why should utilities invest in assets if sunk costs are not to be recovered under new regulation? This fact would attribute to either delaying or undertaking the bare essential in transmission network strengthening. The spare transfer capability (STC) would then be small. The researcher assumes that the additional costs to refurbish an existing transmission network to provide the regulators minimum continuity and quality of supply are considered a “sunk cost”. The continuity and quality of supply is described in detail under *Chapter 5: Primary Variable Reliability Under Discussion*.

4.2.3 Addressing complexities in transmission network utilisation.

Dr. Eric Hirst found that utilities generally agreed on the need for additional transmission facilities according to specific qualifications. The qualifications had three themes. Firstly, several utilities mentioned the application of improved data collection, communications, and computing systems as a way to effectively increase transmission capacity by operating closer to transmission limits. The second qualification is the proper location of new generators as an alternative to new transmission. Generators located close to load centers can reduce the need for new transmission. The New York City case cited in the Introduction is a good example of this approach, in which generation substitutes for transmission. Thirdly, small-scale transmission investments (e.g., static VAR compensators, capacitor banks, and line upgrades) may yield large benefits relative to their financial, social and political costs.

The most basic complexity in electricity markets is the real-time balance of supply and demand due to the physical inability to efficiently store electricity. This task is made difficult because of uncertainties in both supply and demand. Transmission network risk to supply can be large and unpredictable due to the failure of substation plant and equipment or a single transmission line. This fact requires that the system operator have a significant quantity of flexible network configuration options and resources that can quickly respond to contingencies. Properly rewarding these flexible reserve resources is a major challenge of the market design.

A second complexity is a near vertical demand curve which represents little demand response to price. Unresponsive demand is a problem because supply is generally highly concentrated in many markets. This means that the market is vulnerable to the exercise of market power on the supply side. Subsequently, the demand side is unable to protect itself by curtailing demand in response to high prices. The problem of market power becomes worse as the system approaches real time. Under these conditions the supply curve becomes steeper as options diminish closer to real time.

Thirdly, bidding non-convexities further complicate the design problem. On the supply side, there are start-up and no-load costs (spinning reserve costs). Generating units have minimum run times and they are limited in their ability to ramp up and down. These constraints create “intertemporal” dependencies in which a unit may have to be started and ramped up hours before it is needed. Similarly, industrial demand may also have intertemporal dependencies, such as a plant that requires energy over several adjacent hours to complete its production process.

A fourth source of complexity is transmission network constraints. Typically, every operational incident impacts all customers on a transmission network. As a result, transmission network expansion and pricing must reflect the network constraints and operational contingencies. This topic is discussed in more detail under section *4.2.6 System Operating Constraints.*

Sound transmission network planning begins with an understanding of the market participants, their incentives, and the economic objective that the market is trying to address. With this understanding in place, a good design follows almost from common sense. Certainly, many of the fatal flaws in actual electricity markets become obvious when the problem is analysed in the right way. Why then do these flaws so often appear and persist? Dr. Eric Hirst is brave enough to state: “One explanation is that common sense is scarce.” The design problems actually are much trickier than meets the eye. There are many ways to look at the problem and only in hindsight does the problem become obvious. This is especially true in electricity markets, where the markets necessary are highly complex and many of the design problems involve serious challenges.

There are at least two practical difficulties with this approach. First, planning is difficult. Planned resources may or may not appear. There is likely to be disagreement about what resources are under-provided. The second problem is that by only subsidising new resources, there is a second explanation for the appearance and persistence of design flaws which has to do with the design process. In the case of electricity this process has most often been designed by a committee of interested parties. More often than not, design proposals were motivated by special interests. The final designs involved a bargaining compromise that tended to focus on the split of gains among special interests, rather than a design that best achieved the market's objective.

4.2.4 System Operating Constraints

Reference to Dr. Eric Hirst regarding transmission network system operating constraints. Operating constraints stem from security and reliability concerns related to maintaining power flows. Power flow patterns redistribute when demand and generation patterns change, or when the system grid is altered due to a circuit being switched on or put out of service. When power is transmitted from one utility, or control area, to another, the resulting power flows along all paths joining the two areas, regardless of ownership of the lines. The amount of power transmitted on each path of the system depends on the impedance of the various paths. Impedance is the opposition to the power flow on an AC circuit. Moreover, impedance depends on the length of the line and design details for the line. A path of low impedance attracts a greater part of the total transfer than a path of high impedance.

In a wholesale power transaction, a pro forma "contract path" of transmission lines or systems is designated through which the power is expected to flow. However, the actual power flows do not necessarily follow the contract path but may flow through parallel paths in other transmission systems depending on the loading conditions at that time. These are known as "parallel path flows." "Loop flows" are a result of interconnected transmission systems whereby power flows can inadvertently travel into the other systems' networks and return. This reiterates the point that power flow is controlled by physics, not contracts.

Currently, it is not a requirement of law that contracts reflect the actual path. Parallel path flows and loop flows can limit the transfer capability of other systems that are not a part of the scheduled contract path.

Preventive operation for system security also represents constraints on system operation. The bulk power system is designed and operated to avoid service interruptions, referred to as "contingencies," due to component outages such as loss of a generation unit, loss of a transmission line, or a failure of a single component of the system. The adoption of NERC guidelines has increased security of interconnected systems throughout its jurisdiction by requiring systems to operate in such a manner that they can withstand the single largest contingency possible and, when practical, withstand multiple contingencies. The preventive operating guidelines provided by the NERC include running sufficient generation capability to provide operating reserves in excess of demand and limiting power transfers on the transmission system. This allows the system to operate so that each element remains below normal thermal constraints under normal conditions and under emergency limits during contingencies. Proper levels of reserve capacity accommodate contingencies.

One of the advantages of an interconnected system is reserve sharing. Utility management must have access to additional power facilities (reserves) that can be put into service either immediately (spinning reserves) or after a short period of preparation (supplemental reserves). This reserve capacity is needed in case of contingencies or customer demand in excess of plant capability. Reserves may be obtained from spare generating units or through interconnection. If a contingency occurs in one company, power can be supplied temporarily by the other companies. Thus, an interconnected system of reliable suppliers enhances overall reliability and decreases the reserve levels needed by independent utilities. This assumes that each supplier in an interconnected system provides proportionate reserve margins to accommodate the variations of demand and for unexpected breakdowns of generators. The proper level of generating reserves (i.e., reserve margin) depends on system characteristics, such as types of generators, load growth, demand conditions and operating policies. In addition, reserves can be planned by interruptible arrangements such as risk of trip conditions. Some utilities make large sales to interruptible customers whose service the utility can turn off at will. Normally, the desired reserve margin is set by a loss of load probability (LOLP) analysis designed to assure that blackouts and brownouts will be limited.

System operating constraints also involve system stability. Problems associated with system stability are typically grouped into two types: (1) maintaining synchronisation among system generators and (2) preventing voltage collapse. In the United States, interconnected systems are considered synchronous when all generators rotate in unison at a speed that produces a consistent frequency of 60 hertz (cycles per second). Disturbances (i.e., faults) and their removal cause oscillations in the speed at which the generator rotates and in the frequency of the power flows in the system. Unless natural conditions or control systems damp out the oscillations, the system is unstable and transient instability can lead to the collapse of the system. These unstable conditions can lead to large voltage and frequency fluctuations.

Finally, voltage collapse can occur from a chain of events that stem from voltage instability. This occurs if transmission lines are not adequately designed to handle large amounts of reactive power, resulting in severe voltage drops at the receiving end. This causes the consuming entities to draw increasing currents that create additional reactive power flows and voltage losses in the system. If the process continues, voltages can collapse further and may require users to be disconnected in order to prevent serious damage. Not only does “obvious” reactive power cause instability, but so does ferro-resonance. Where capacitor banks are installed on the system, contingency studies must include the effects of non-linear reactance such as transformers and voltage transformers. There have been occurrences on the Eskom 132kV where surge arresters have failed due to overvoltage conditions caused by ferro-resonance.

4.2.5 Utilisation and the changing credit risk criteria.

Returning to John Elkington's triple bottom line and reviewing "affordability" as the economic bottom line in the context of transmission utilisation. For economic sustainability, utilities must invest in physical, financial, human and intellectual capital. The former contribute to innovation in technology which ultimately determines whether a utility will be sustainable in the long-term. Part of the capital investment relates to quantitative credit risk criteria in procuring financial assets. This is more pronounced in shareholding utilities. The traditional model of the concept of "option pricing technology" is based on the option pricing formula of Black and Scholes which applies the principle of stock options to the field of credit risk. Two main models have emerged from this concept. The first being *structural models*, which review the balance sheet of a company to evaluate its financial strength. The second, called the *default intensity model,* considers the default to be a random event, the cause of which lies in the general state of the economy rather than in the balance sheet of a company – similar to the actuarial approach in insurance.

In structural models, the default is determined by the relationship between the value of a firm and its liabilities. These models assume that corporate debt can be viewed as an option on the assets of a company. The formula provides a pricing method, comparing the value of the assets of a company to the value of its liabilities. If the latter falls below a bottom line equal to its total debts, the company defaults.

A well-known model of this structural type is the Kealhofer, McQuown and Vasicek (KMV) Model, applied by Moody's. The probability of default or Expected Default Frequency (EDF) is estimated by firstly determining the market value of the assets. The market value in the form of the share price is the best indicator of asset value. Traditionally the asset value of an electric utility was determined by summing up tangible plant and equipment, and goodwill was determined through a customer base and general public opinion. For network operators (non-asset holding entities) tangible assets make up a small percentage of their total asset value. The KMV model determines the asset value from the market value of the utilities share equity. This was initially introduced by the economist, Robert Merton, who proposed the share price of a company as being representative of the price of an option on the value of the company's assets.

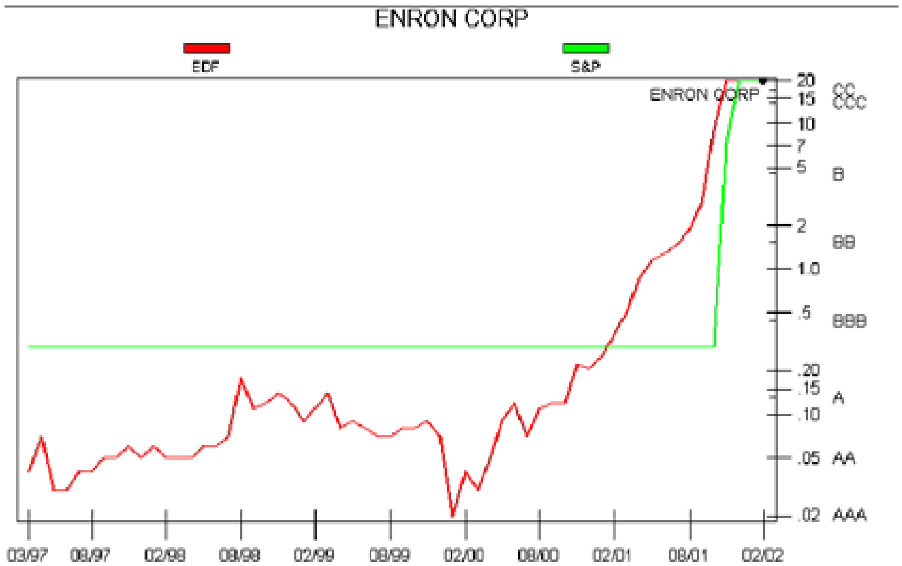
Secondly, the volatility of the asset value is measured, highlighting the risks that reside in the asset value. And finally, the default point is determined as the point where the asset value drops below the value of current liabilities.

Reviewing the historical trend of the share equity price also gives an insight into the price volatility of a firm. The amplitude of share price movements over a period of time influences the value of a firm. Additional factors that need to be considered are the leverage ratio of debt versus equity, the structure of the liabilities, the average coupon paid on the debts, and the risk free rate, which is the interest rate that governments pay on their debts. In summary, the three main variables driving Expected Default Frequency (EDF) are stock price, debt level and asset volatility.

How does the above concern electric utilities and transmission network utilisation?

Firstly, The Enron case is a recent example and is illustrated in *Figure 4.4: The Expected Default Frequency (EDF) of ENRON.* The green line, shows the Standard and Poor's rating, remains stable until the last. The red curve, indicates EDF, rises dramatically after September 2001. A few months later, the company went bankrupt. In less than a year ENRON fell from $84 to $8.41. The company was, at its peak, valued at nearly $70 billion.

EDF/ Standards & Poor's Rating



Source: Credit Monitor (see http://www.kmv.com)

Figure 4.4 The Expected Default Frequency (EDF) of ENRON.

Secondly, electric utilities are vulnerable as they are exposed to short-term and long-term uncertainty consisting of generation availability, transmission capacity, and load and distribution considerations. Transmission capacity contributing factors include line ratings, weather-related factors such as wind and ice storms, geophysical events (lightning and earthquakes), geomagnetic storms, unplanned outages and equipment failures [4.1 p7]. A single blackout can impact severely on the share equity value of a listed electric utility. The question policy making managers must ask is … "does the risk to the share equity value not exceed the capital costs to expand or refurbish the transmission network?" The researcher believes that this must be considered in the expansion criteria decisions. Investment decisions based on traditional economic evaluation must be expanded to include the affects of major system disturbances on the share equity value.

4.3 Input Data

The input data for the measurement of the above identified utilisation indices are:

- Maximum demand – measured in Megawatts (MW) and defined as annual peak demand.
- Total energy demanded – measured in Megawatt-hours (MWh) and defined as total annual MWh delivered from the transmission network.
- Total energy losses – difference between annual imported energy and energy supplied to the customer point of supply (MWh).
- Number of installed transformers – the total number of transmission substation transformers at points of supply and transformation substations.
- Maximum Demand (MW) / Total Energy Demanded (MWh) [U_4].

The data under investigation is tabulated in *Table 4.3: Transmission Utilisation Raw Data* and has been extracted from the NGC International Transmission Benchmarking questionnaire.

Table 4.3: Transmission Utilisation Raw Data.

Utility	Max. Demand	MWh loss	Total MWh	TX. Line length	Number of Trfrs.	System Minutes	No. of Interrupt.
E_1	2313	316331.8	10488013	5545.25	96	8.84	41
E_2	4822	124697	27710376	9203	114	1.78	122
E_3	5250	797000	29281000	5707	112	3.70	207
E_4	5309	701310	32702395	4024	261	2.54	109
E_5	5421	1648839	31214479	9331	116	2.00	926
E_6	5678	1469000	33610000	16123	531	6.08	353
E_7	6213	1702244	37827636	6539	156	1.87	72
E_8	6920	6,768	40964756	6663	147	4.00	65
E_9	7422	1677968	43348860	7132	36	55.00	436
E_{10}	9769	1420403	31564500	7443	35	95.83	459
E_{11}	10624	1730250	57259959	12023	158	0.89	65
E_{12}	11083	750000	68550000	11446	81	1.50	280
E_{13}	13891	3194607	65719129	9534	928	4.88	303
E_{14}	15993	4327759	91689803	9580	466	5.72	150
E_{15}	16132	6553397	139433986	23872.2	1123	5.63	840
E_{16}	17166	1700000	114750000	8683	143	2.71	198
E_{17}	22764	4775320	141660000	29155	743	9.30	862
E_{18}	23253	1736645	143692500	12628	158	34.37	316
E_{19}	23309	2366666	139000000	15223	26	0.43	226
E_{20}	26557	2248400	157947589	18174	222	0.07	666
E_{21}	27447	4737104	170619400	26460	432	6.03	1457
E_{22}	48305	5241500	283807400	14378.6	763	0.20	293

The performance measures for utilisation are the following:

- Maximum Demand (MW)/Number of Installed Transformers [U_1].
- Maximum Demand (MW)/Length of Transmission Lines (km) [U_2].
- Energy Losses (MWh)/Total Energy (MWh) [U_3].
- Maximum Demand (MW) / Total Energy Demanded (MWh) [U_4].

The criteria for choosing the above performance measures are the following: The maximum demand is the real time point at which the maximum critical transfer capacity takes place. At this point the asset utilisation of lines and transformers are measured, as well as providing an indication of spare capacity relative to other benchmarked utilities. Ideally the study should have included the amount of transformer capacity installed. However, the trending of the maximum demand (MW)/Number of Installed Transformers will provide an indication of growing utilisation. In addition, the energy losses as a function of total energy and length of transmission lines does provide a measurement of transmission network efficiency.

The length of transmission lines have not been categorized in transmission voltage levels. This decision was to accommodate all of the various international voltage levels e.g. 110kV versus 132kV, or 400kV versus 440kV. The researcher is however aware that the energy transported is proportional to the system voltage levels.

The researcher acknowledges that there are many options to measure the network utilisation. The above choice was based on available data and the reasonable assumption that these would address the required research output for electrical network utilisation.

The initial raw data is processed according to the above utilisation performance measures and represented in *Table 4.3.2: Raw Data Processed Without Masking the Outliers.*

Table 4.4 Raw Data Processed Without Masking the Outliers.

Utilities	U_1	U_2	U_3	U_4
E_1	24.09375	0.4171	0.03016	0.0002205
E_2	42.298246	0.524	0.0045	0.000174
E_3	46.875	0.9199	0.02722	0.0001793
E_4	20.340996	1.3193	0.02145	0.0001623
E_5	46.732759	0.581	0.05282	0.0001737
E_6	10.693032	0.3522	0.04371	0.0001689
E_7	39.826923	0.9501	0.045	0.0001642
E_8	47.07483	1.0386	0.00017	0.0001689
E_9	206.16667	1.0407	0.03871	0.0001712
E_{10}	279.11429	1.3125	0.045	0.0003095
E_{11}	67.240506	0.8836	0.03022	0.0001855
E_{12}	136.82716	0.9683	0.01094	0.0001617
E_{13}	14.96875	1.457	0.04861	0.0002114
E_{14}	34.319742	1.6694	0.0472	0.0001744
E_{15}	14.365093	0.6758	0.047	0.0001157
E_{16}	120.04196	1.977	0.01481	0.0001496
E_{17}	30.637954	0.7808	0.03371	0.0001607
E_{18}	147.17089	1.8414	0.01209	0.0001618
E_{19}	896.5	1.5312	0.01703	0.0001677
E_{20}	119.62613	1.4613	0.01424	0.0001681
E_{21}	63.534722	1.0373	0.02776	0.0001609
E_{22}	63.309305	3.3595	0.01847	0.0001702

On closer observation it becomes clear that the data above contains a number of outliers which, if not masked, will distort the final results. It must be remembered that the data available is over five years and during that period utility data may have changed significantly from year to year. Reasons for this change could be that an electricity utility may have changed its asset base by either obtaining new assets or scaling down. This will be seen in the performance data as maximum demand and total energy transferred changes with the change in asset base. In addition, some electricity utilities experienced exceptional outages due to abnormal environmental conditions – similar to the outages experienced in the northern regions of America. To accommodate these variations average data were obtained over the five years. Where data was missing for a specific year the data was averaged over the available period. A simple box plot was performed to identify and exclude the outliers. This is illustrated in *Figure 4.5: Box Plot for U_1 Values.* The data contains two outliers which have been masked in the final processed data. The spread between the main data for U_1 is contained within 14.365093 and 206.16667.

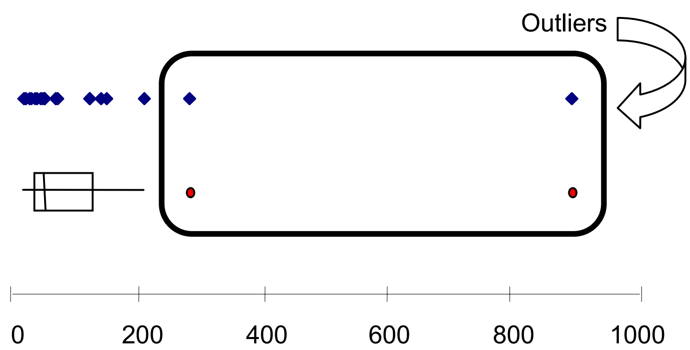


Figure 4.5: Box Plot of U_1 Values.

Figure 4.6: Box Plot of U_2 Values illustrates similar. The data contains only one outlier which has been masked in the final processed data. The spread between the main data for U_2 is contained within 0.35216 and 1.8414.

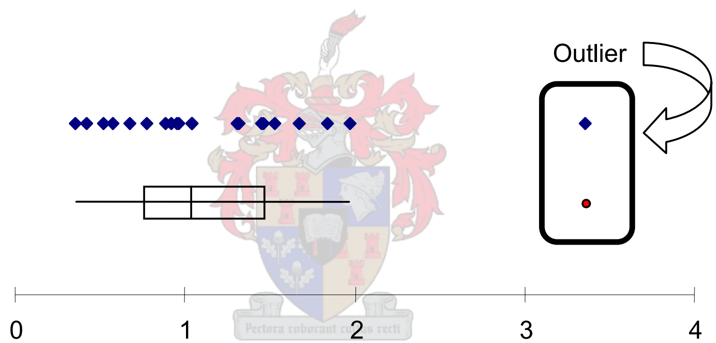


Figure 4.6: Box Plot of U_2 Values.

And, *Figure 4.7: Box plot of U_3 values* illustrates similar. The data contains no outliers The spread between the main data for U_3 is contained within 1.65215 and 5.28229.

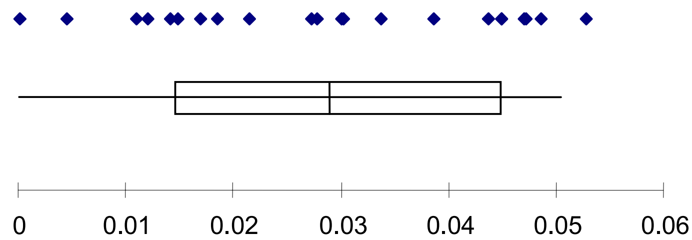


Figure 4.7: Box Plot of U_3 Values.

Once again, *Figure 4.8: Box Plot of U_4 Values*. The data contains four outliers which have been masked in the final processed data. The spread between the main data for U_2 is contained within 0.0001607 and 0.0001855. The remaining data are evenly distributed.

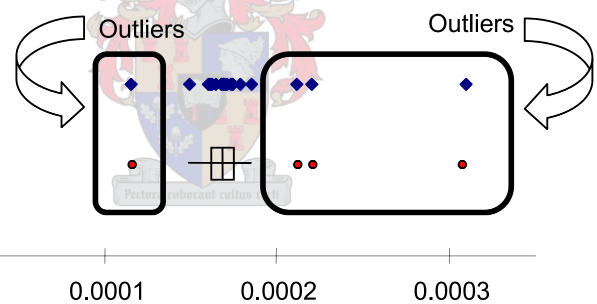


Figure 4.8: Box Plot of U_4 Values.

A summary of the masked outliers is presented in *Table 4.5 Summary of Box Plot U Values.*

Table 4.5: Summary of Box Plot U Values.

	U_1	U_2	U_3	U_4
Smallest Value	10.69303	0.35216	1.65215	1.15696
Q1	29.00190	0.75453	1.46698	1.61787
Median Value	46.97491	1.03793	0.028962	1.68931
Q3	124.23825	1.47874	4.500001	1.75643
Largest Value	896.5	3.35950	5.28229	3.09493
IQR	95.23635	0.72420	3.033012	1.38551
Outliers	***896.5*** ***279.1***	***3.35950***	None	***3.09493E-04*** ***2.20537E-04*** ***2.11369E-04*** ***1.15696E-04***

. To complete the data matrix for both the principal component analysis and the factor analysis, the outliers were replaced with the median values. These revised values are presented in *Table 4.6 Raw Data Processed With Outlier Elimination*. The values which are documented in bold italics have replaced the previous outliers.

Table 4.6: Raw Data Processed With Outlier Masking.

Utility	U_1	U_2	U_3	U_4
E_1	24.09375	0.4171	0.03016	***1.68931***
E_2	42.298246	0.524	0.0045	0.000174
E_3	46.875	0.9199	0.02722	0.0001793
E_4	20.340996	1.3193	0.02145	0.0001623
E_5	46.732759	0.581	0.05282	0.0001737
E_6	10.693032	0.3522	0.04371	0.0001689
E_7	39.826923	0.9501	0.045	0.0001642
E_8	47.07483	1.0386	0.00017	0.0001689
E_9	206.16667	1.0407	0.03871	0.0001712
E_{10}	***46.97491***	1.3125	0.045	***1.68931***
E_{11}	67.240506	0.8836	0.03022	0.0001855
E_{12}	136.82716	0.9683	0.01094	0.0001617
E_{13}	14.96875	1.457	0.04861	***1.68931***
E_{14}	34.319742	1.6694	0.0472	0.0001744
E_{15}	14.365093	0.6758	0.047	***1.68931***
E_{16}	120.04196	1.977	0.01481	0.0001496
E_{17}	30.637954	0.7808	0.03371	0.0001607
E_{18}	147.17089	1.8414	0.01209	0.0001618
E_{19}	***46.97491***	1.5312	0.01703	0.0001677
E_{20}	119.62613	1.4613	0.01424	0.0001681
E_{21}	63.534722	1.0373	0.02776	0.0001609
E_{22}	63.309305	***1.03793***	0.01847	0.0001702

4.4 Application of Principal Component Analysis

Following the procedure as presented in *Chapter 3: Data Collection, Processing & Evaluation Methodology (p3.8)* of this research document.

Principal Component Analysis (PCA) was performed with software XLSTAT 6.1.9. There were 22 numbers of observations (rows) and 4 variables (columns) with no missing values. A Pearson correlation coefficient was performed without axes rotation. Number of factors associated with non trivial eigenvalues: 4

4.4.1 Bartlett's Sphericity Test

The first statistics of interest from the generated output when applying principal component analysis is the determinant of the correlation matrix.

The Bartlett's sphericity test tests the null hypothesis that the population correlation matrix is an identity matrix. If the obtained chi-square value is significant, then the correlation matrix to be analyzed is non-random. The Bartlett's sphericity test reveals the following results in *Table 4.7: Bartlett's Sphericity Test For Utilisation Data.*

Table 4.7: Bartlett's Sphericity Test For Utilisation Data.

Chi-square (observed value)	5.692
Chi-square (critical value) (df = 6)	12.592
One-tailed p-value	0.459
Alpha	0.050

The Chi-square critical value is the value of the statistics under the null hypothesis for the probability 1-alpha (right-tailed test). One can reject the null hypothesis when the observed value is greater than the critical value. This is the case above where the observed value is 44.550 and the critical value is only 12.592. Therefore, the null hypothesis is rejected.

For the one-tailed p-value, the null hypothesis is rejected when the probability is lower than the alpha level. Again the null hypothesis is rejected because the probability is smaller than 0.0001 and alpha is 0.050. At the level of significance alpha=0.050 the decision is to reject the null hypothesis of absence of significant correlation between variables.

Means and standard deviations of the variables are represented in *Table 4.8: Means and Standards for Utilisation Data.*

Table 4.8: Means and Standards for Utilisation Data.

	Mean	Standard deviation
U_1	63.186	49.717
U_2	1.186	0.645
U_3	0.029	0.015
U_4	0.000	0.000

Correlation matrix is represented in *Table 4.9: Correlation Matrix*. The significant values (except diagonal) would be represented in bold and at a level of significance alpha=0.050 (two-tailed test). The results show that there is no correlation between the values.

Table 4.9: Correlation Matrix.

	U_1	U_2	U_3	U_4
U_1	1	0.263	-0.345	-0.143
U_2	0.263	1	-0.262	-0.013
U_3	-0.345	-0.262	1	0.239
U_4	-0.143	-0.013	0.239	1

4.4.2 Eigenvalues of a matrix :

The next table under consideration is related to a mathematical object, the *eigenvalues*, which reflect the quality of the projection from the 4-dimensional variables. The results have produced 4 eigenvalues by use of XLSTAT-Pro. The results of these values and their associated percentage variance and percentage cumulative values are tabulated in *Table 4.10: Eigenvalues for R_3.*

Ideally, the first two or three eigenvalues must correspond to a high % of the variance, ensuring that the maps based on the first two or three factors are a good quality projection of the initial multi-dimensional table. In this example,

Table 4.10. Eigenvalues for Utilisation.

	U_1	U_2	U_3	U_4
Eigenvalue	1.667	0.997	0.707	0.629
% variance	41.678	24.917	17.673	15.732
% cumulative	41.678	66.595	84.268	100.000

4.4.3 Eigenvectors of a matrix

Associated with each eigenvalue is a vector, **v**, called the *eigenvector*. The results are represented in *Table 4.11 Eigenvector Values For Utilisation*.

Table 4.11 Eigenvector Values For Utilisation.

	U_1	U_2	U_3	U_4
U_1	-0.562	0.130	0.683	0.447
U_2	-0.462	0.565	-0.642	0.235
U_3	0.595	0.097	-0.050	0.796
U_4	0.342	0.809	0.345	-0.332

Each eigenvalue corresponds to a factor, and each factor to one variable. A factor is a linear combination of the initial variables, and all the factors are un-correlated (r=0). The eigenvalues and the corresponding factors are sorted by descending order of how much of the initial variability they represent.

4.4.4 Correlation circle

The first correlation circle is illustrated in *Figure 4.9: Correlation Circle for F1 and F2.* It represents the projection of the initial variables in the factors space. When two variables are far from the center, then, if they are:

- Close to each other, they are significantly positively correlated (r close to 1);

- If they are orthogonal, they are not correlated (r close to 0);
- If they are on the opposite side of the center, then they are significantly negatively correlated (r close to -1).

When the variables are close to the center, it means that some information is carried on other axes, and that any interpretation might be erroneous.

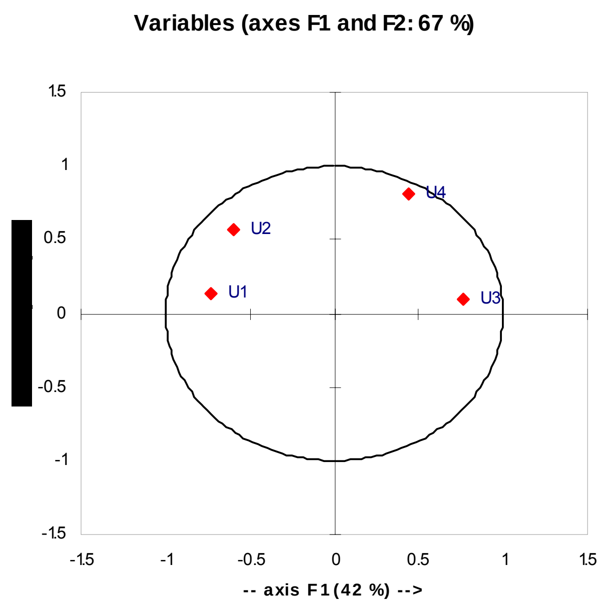


Figure 4.9: Correlation Circle for F1 and F2.

The correlation circle is useful in interpreting the meaning of the axes. In the above the horizontal axis F1 is linked to U_1 (System minutes/maximum demand), and the vertical axis *U2* (System minutes/total MWh). To confirm that a variable is well linked with an axis, the squared cosines table is reviewed. The greater the squared cosine, the greater the link with the corresponding axis. The closer the squared cosine of a given variable is to zero, the more careful the researcher has to be when interpreting the results in terms of trends on the corresponding axis. Reviewing *Table 4.12: Squared Cosines of the Variable Utilisation*, we can see that utilisation would be best viewed on a F1/F2 map (see encircled values).

Table 4.12: Squared Cosines of the Variable Utilisation

	F1	F2	F3	F4
U_1	0.527	0.017	0.330	0.126
U_2	0.355	0.319	0.291	0.035
U_3	0.590	0.009	0.002	0.399
U_4	0.195	0.652	0.084	0.069

The observations relative to these factors are illustrated in *Figure 4.10: Utilisation Observations.* The residual vector can be assumed to be negligible due to the masking of the outliers from the original data.

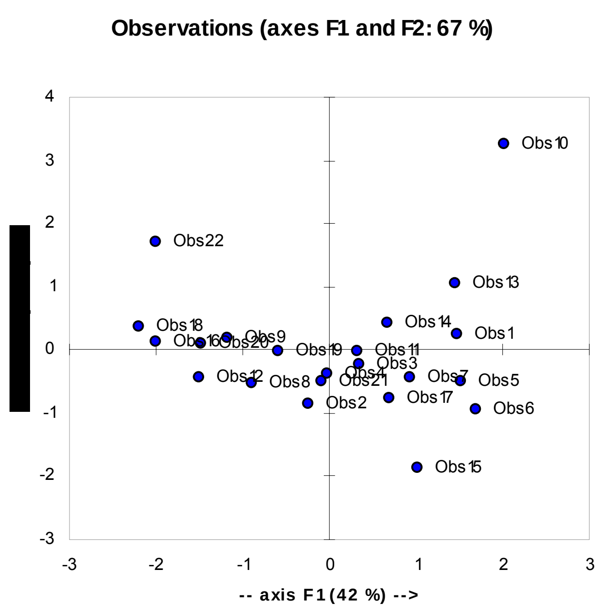


Figure 4.10: Utilisation Observations.

4.5 Determining the number of principal components.

The above simulation has produced 4 principal components (F1, F2, F3 and F4). The question is: how many of these principal components do we retain? With no definite answers, Johnson & Wichern [5.31] have proposed guidelines. The following have to be considered.

- Relative sizes of the eigenvalues.
- Subject matter interpretations of the components.
- Amount of total sample variance explained.
- A component associated with an eigenvalue near zero may indicate an unsuspected linear dependency in the data.

Furthermore, a useful visual aid to determine the number of principal components is the scree plot. The scree plot is a plot of the magnitude of components λ_i versus its number (i). Plotting from the data obtained from *Table 4.10: Eigenvalues for Utilisation*, presents the scree plot as illustrated in *Figure 4.11 Utilisation Scree Plot.* The elbow occurs in the plot at i = 3 (between 2 and 3). That is, the eigenvalues after λ_2 are all relatively small and approximately the same size. The conclusion can be drawn that only two principal components effectively summarise the total sample size.

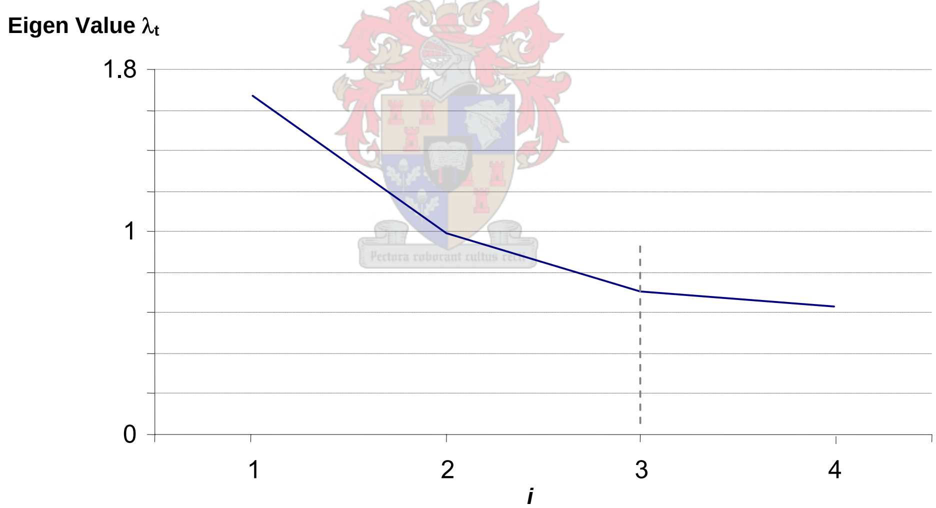


Figure 4.11 Utilisation Scree Plot.

4.6 <u>Remaining principal component findings</u>.

The following are the remaining principal component values which have been documented as factor loadings, contributions of the variables, factor scores, squared cosines of the observations and contributions of the observations (%).

Table 4.13: Factor Loadings.

	F1	F2	F3	F4
U_1	0.782	0.488	0.388	-0.026
U_2	0.597	0.726	-0.341	0.018
U_3	0.850	-0.474	-0.022	0.228
U_4	0.838	-0.491	-0.097	-0.219

Table 4.14: Contributions of the Variables (%).

	F1	F2	F3	F4
U_1	31.629	1.694	46.672	20.005
U_2	21.323	31.965	41.185	5.527
U_3	35.366	0.947	0.254	63.432
U_4	11.681	65.394	11.889	11.036

Table 4.15: Factor Scores

Utilities	F1	F2	F3	F4
U_1	1.481	0.253	0.658	-0.974
U_2	-0.245	-0.842	0.427	-1.655
U_3	0.347	-0.218	0.074	-0.347
U_4	-0.026	-0.365	-0.836	-0.577
U_5	1.524	-0.484	0.270	0.904
U_6	1.698	-0.945	-0.014	0.071
U_7	0.944	-0.445	-0.259	0.662
U_8	-0.884	-0.524	-0.055	-1.600
U_9	-1.177	0.191	2.026	1.801
U_{10}	2.022	3.245	0.909	-0.519
U_{11}	0.320	-0.033	0.442	-0.081
U_{12}	-1.504	-0.450	1.142	-0.193
U_{13}	1.462	1.045	-0.652	0.363
U_{14}	0.676	0.420	-0.957	0.892
U_{15}	1.032	-1.861	-0.821	0.897
U_{16}	-2.005	0.136	-0.224	0.338
U_{17}	0.699	-0.771	-0.215	-0.032
U_{18}	-2.201	0.353	0.413	0.276
U_{19}	-0.597	-0.014	-0.613	-0.539
U_{20}	-1.472	0.107	0.468	-0.060
U_{21}	-0.084	-0.494	0.003	0.049
U_{22}	-2.010	1.697	-2.187	0.324

Table 4.16: Squared Cosines of the Observations

Utilities	F1	F2	F3	F4
U_1	0.603	0.018	0.119	0.261
U_2	0.016	0.192	0.049	0.742
U_3	0.411	0.162	0.019	0.409
U_4	0.001	0.115	0.599	0.286
U_5	0.674	0.068	0.021	0.237
U_6	0.762	0.236	0.000	0.001
U_7	0.559	0.124	0.042	0.275
U_8	0.216	0.076	0.001	0.707
U_9	0.158	0.004	0.468	0.370
U_{10}	0.260	0.670	0.053	0.017
U_{11}	0.335	0.004	0.640	0.021
U_{12}	0.595	0.053	0.343	0.010
U_{13}	0.565	0.288	0.112	0.035
U_{14}	0.195	0.075	0.391	0.339
U_{15}	0.177	0.577	0.112	0.134
U_{16}	0.957	0.004	0.012	0.027
U_{17}	0.433	0.526	0.041	0.001
U_{18}	0.929	0.024	0.033	0.015
U_{19}	0.349	0.000	0.367	0.284
U_{20}	0.903	0.005	0.091	0.001
U_{21}	0.028	0.963	0.000	0.010
U_{22}	0.342	0.244	0.405	0.009

Table 4.17: Contributions of the Observations (%)

Utilities	F1	F2	F3	F4
U_1	5.980	0.291	2.781	6.851
U_2	0.164	3.235	1.174	19.789
U_3	0.329	0.217	0.035	0.867
U_4	0.002	0.609	4.490	2.406
U_5	6.334	1.067	0.470	5.909
U_6	7.860	4.075	0.001	0.036
U_7	2.432	0.904	0.431	3.168
U_8	2.132	1.251	0.019	18.500
U_9	3.775	0.166	26.389	23.418
U_{10}	11.145	48.023	5.312	1.948
U_{11}	0.279	0.005	1.255	0.047
U_{12}	6.170	0.922	8.384	0.270
U_{13}	5.828	4.978	2.738	0.950
U_{14}	1.247	0.803	5.889	5.744
U_{15}	2.904	15.790	4.329	5.812
U_{16}	10.959	0.084	0.321	0.825
U_{17}	1.334	2.710	0.297	0.007
U_{18}	13.203	0.568	1.099	0.549
U_{19}	0.973	0.001	2.419	2.100
U_{20}	5.912	0.052	1.409	0.026
U_{21}	0.019	1.111	0.000	0.017
U_{22}	11.020	13.139	30.757	0.760

4.5 Application of Factor Analysis

4.5.1 Introduction

NIST/SEMATECH e-Handbook of Statistical Methods provides basic guidelines and definitions to the statistical analysis of engineering problems. These have been incorporated with XLSTATS-Pro to produce the following factor analysis results.

XLSTATS-Pro utilises the maximum likelihood estimation which begins with the mathematical expression known as a likelihood function of the sample data. That is, the likelihood of a set of data is the probability of obtaining that particular set of data given the chosen probability model. This expression contains the unknown parameters. Those values of the parameter that maximize the sample likelihood are known as the maximum likelihood estimates.

The advantages of this method are:

- Maximum likelihood provides a consistent approach to parameter estimation problems. This means that maximum likelihood estimates can be developed for a large variety of estimation situations. For example, they can be applied in utilisation analysis to censored data under various censoring models.
- Maximum likelihood methods have desirable mathematical and optimality properties. Specifically, they become minimum variance unbiased estimators as the sample size increases. By unbiased, we mean that if we take (a very large number of) random samples with replacement from a population, the average value of the parameter estimates will be theoretically exactly equal to the population value. By minimum variance, we mean that the estimator has the smallest variance, and thus the narrowest confidence interval, of all estimators of that type. Furthermore, they have approximate normal distributions and approximate sample variances that can be used to generate confidence bounds and hypothesis tests for the parameters.

However, the disadvantages of the maximum likelihood estimation method are:

- The likelihood equations need to be specifically solved for a given distribution and estimation problem. The mathematics is often non-trivial, particularly if confidence intervals for the parameters are desired.
- The numerical estimation is usually non-trivial. Except for a few cases where the maximum likelihood formulas are in fact simple, it is generally best to rely on high quality statistical software to obtain maximum likelihood estimates.
- Maximum likelihood estimates can be heavily biased for small samples. The optimality properties may not apply for small samples.
- Maximum likelihood can be sensitive to the choice of starting values.

The statistical software XLSTATS-Pro provides algorithms for the maximum likelihood estimates for many of the commonly used distributions. This helps mitigate the computational complexity of maximum likelihood estimation.

4.5.2 Results

XLSTATS-Pro 6.1.9 produced the following Factor Analysis results. Utilisation data utilised was XL-Spreadsheet with 22 rows and 4 columns. There were no missing values and Pearson correlation coefficient was applicable. No axis rotation was performed as there was only one factor. 200 iterations were processed with a convergence of 0,001.

Several methods are available for computing factor analysis. *XL*STAT default method is the *Principal factor method* applied iteratively. It was applied to generate the single factor, and because we could only generate one factor, a varimax rotation could not be performed. There were no missing values and again the Pearson correlation coefficient was applied. There were 51 performed iterations with a convergence of 0.001.

The means and standard deviations of the variables are tabulated in Table 4*.18: Means and Standard Deviations for Utilisation*.

Table 4.18: Means and Standard Deviations for Utilisation.

	Mean	**SD**
U_1	63.186	50.887
U_2	1.186	0.660
U_3	0.029	0.016
U_4	0.000	0.000

The correlation matrix is represented in *Table 4.19: The Utilisation Correlation Matrix.* There were no significant correlation values at the level of significance alpha = 0.050. This is to be considered in *Chapter 7: Discussion Emanating from the Research*, and proves the same result as in the principal component studies.

Table 4.19: The Utilisation Correlation Matrix.

	U_1	U_2	U_3	U_4
U_1	1	0.263	-0.345	-0.143
U_2	0.263	1	-0.262	-0.013
U_3	-0.345	-0.262	1	0.239
U_4	-0.143	-0.013	0.239	1

The following table shows the eigenvalues resulting from the factor analysis. It can be seen that from *Table 4.20: Eigenvalues for the Utilisation Factor*, that the single-factor solution retains 79.159% of the variability of the initial data.

Table 4.20. Eigenvalues for the Utilisation Factor.

	F1	F2
Eigenvalue	1.013	0.267
total % variance	25.313	6.665
% cumulative	25.313	31.977
common % variance	79.159	20.841
% cumulative	79.159	100.000

Table 4.21. Eigenvectors for the Utilisation Factor.

	F1	F2
U_1	-0.536	0.129
U_2	-0.443	0.625
U_3	0.649	0.177
U_4	0.309	0.750

Table 4.22: Factor Loadings for the Utilisation Factor.

	F1	**F2**	**Initial Communality**	**Final Communality**	**Specific Variance**
U_1	-0.539	0.067	0.156	0.296	0.704
U_2	-0.446	0.323	0.106	0.302	0.698
U_3	0.653	0.091	0.189	0.434	0.566
U_4	0.311	0.387	0.065	0.246	0.754

Table 4.23: Reproduced Correlation Matrix.

Utility	U_1	U_2	U_3	U_4
U_1	0.295	0.262	-0.346	-0.142
U_2	0.262	0.303	-0.262	-0.014
U_3	-0.346	-0.262	**0.434**	0.238
U_4	-0.142	-0.014	0.238	0.246

Table 4.24: Residual Correlation Matrix.

Utility	U_1	U_2	U_3	U_4
U_1	**0.705**	0.000	0.001	-0.001
U_2	0.000	**0.697**	-0.001	0.001
U_3	0.001	-0.001	**0.566**	0.000
U_4	-0.001	0.001	0.000	**0.754**

In bold, significant values at the level alpha=0.050 (two-tailed test). When the method converges with a sufficient precision, the values of the main diagonal are equal to specific variances. The above diagonal values do represent the specific variances.

Table 4.25: Estimated Factor Scores.

Utility	F1	F2
U_1	0.756	0.022
U_2	-0.324	-0.570
U_3	0.167	-0.140
U_4	-0.067	-0.191
U_5	0.996	-0.185
U_6	1.014	-0.469
U_7	0.634	-0.161
U_8	-0.691	-0.384
U_9	-0.519	0.143
U_{10}	1.099	1.550
U_{11}	0.175	-0.043
U_{12}	-0.915	-0.293
U_{13}	0.899	0.583
U_{14}	0.503	0.323
U_{15}	0.728	-0.829
U_{16}	-1.141	0.104
U_{17}	0.416	-0.380
U_{18}	-1.272	0.180
U_{19}	-0.403	-0.021
U_{20}	-0.879	0.028
U_{21}	-0.040	-0.245
U_{22}	-1.135	0.977

4.6 Summary

The results summarized and illustrated in *Table 4.26: Summary of statistical methods – PCA and FA,* show that for purposes of this study the comparative results between both principal component analysis and factor analysis are similar. The specific variance was not applicable to principal component analysis. Results from the factor analysis are to be applied in *Chapter 7: Discussion Emanating from the Research* for the derivation of the composite utilisation index.

Table 4.26: Summary of Statistical Methods – PCA and FA.

	Principal Component Analysis		**Factor Analysis**	
Variables	**Factor Loadings (F_1)**	**Specific Variances**	**Factor Loadings (F_1)**	**Specific Variances**
U_1	-0.726	-	-0.539	0.704
U_2	-0.596	-	-0.446	0.698
U_3	0.768	-	0.653	0.566
U_4	0.441	-	0.311	0.754

The *Utilisation* performance measurement component concluded from this chapter is summarised in the following linear format:

***Utilisation* Component (U_f) = 0.539 U_1 + 0.446 U_2 + 0.653 U_3 + 0.311 U_4 … 4.1**

The above will be discussed and brought into context with the Reliability and Exogenous performance measure components and is discussed in *Chapter 7: Discussion Emanating from the Research* and in a practical example of the application of benchmarking utilisation.

Chapter 5

PRIMARY VARIABLE "RELIABILITY" UNDER DISCUSSION

Chapter Objective

This chapter's objective is to provide a background to the new challenges facing electricity utilities specific to network utilisation in the face of increasing competition, regulation and privatization. The following issues are addressed under the discussion: Addressing complexities in transmission network utilisation, transmission investment at a slower pace than that of generation, rate and magnitude of installed transmission transfer capability, stranded costs in transmission network expansion or refurbishment, addressing complexities in transmission network utilisation, system operating constraints, and utilisation and the changing credit risk criteria. The chapter processes the available data and presents the final linear equation for the primary variable utilisation.

5.1 Chapter Overview

The definition of reliability is not solidly cast within predefined boundaries. NERC defines the reliability of the interconnected bulk electric systems in terms of two basic, functional aspects:

- Adequacy — The ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
- Security — The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

To further expand on the definition, adequacy and security features as the basic and functional aspects of the transmission network. PacifiCorp includes three basic elements of reliability in the accuracy of measurement accuracy. These are:

- Inherency – Includes design, competent operations and maintenance, and minimal exposure to risks and hazards.
- Redundancy – Is the independent backup through alternative supply routes or plant and equipment.
- Recovery – Is the automatic clearing, sectionalizing and reclosing, and human operating response to sustained faults.

Studies reveal that there is no single index that is universally used to express the reliability of a transmission network. *Chapter 2: Literature Research* of the research document makes reference in more detail to this aspect. A composite system reliability would include the assessment of the ability of both generation and transmission to supply adequate (continuity of supply) and suitable (quality of supply) electrical energy. Methods to determine the above include deterministic and probabilistic applications. Keeping in mind that this study relies on actual data and is void of system modeling or predictive theory based on simulation. The main challenges of this chapter are:

- to convince the reader that the chosen reliability indices are warranted and appropriate to this study, and
- that the final single chosen variable for the measurement of reliability attains and maintains credibility within the scope of this study objective.

These chosen indices are amidst numerous existing reliability indices which are currently being utilised and are undergoing continual international discussion, investigation and refinement. The chapter's overview is illustrated in *Figure 5.1: Chapter 5 Overview*, and attempts to justify the researchers chosen reliability indices, provides background into the data input, discusses the application of both principal component analysis and factor analysis, and summarises the basic findings. The section on the extension of cost-benefit of reliability is the researcher's own hypothesis and requires further research. This does not form the main part of this study but does support the direction and decisions taken.

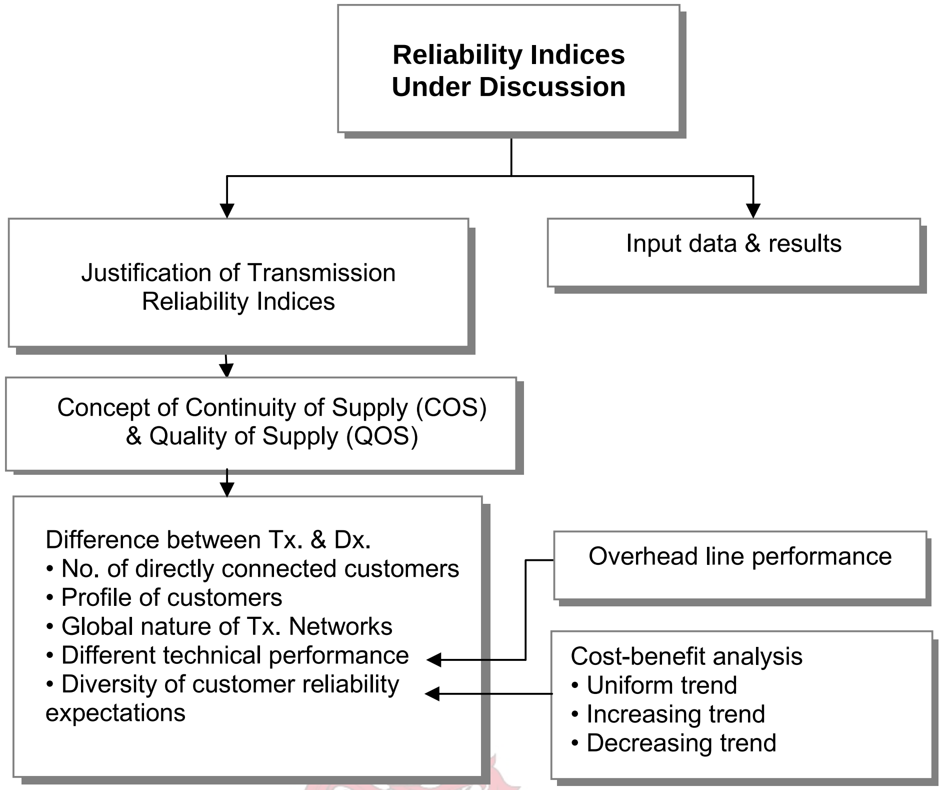


Figure 5.1: Chapter 5 Overview

5.2 Justifying Transmission Reliability Indices

Traditional planning was based on "implicit criteria, planner's intuition and judgement, gut feelings, etc.," [5.1 p1590]. Among regulation and competition, the primary drivers from traditional planning have been the progress in planning technology (advanced network simulation software – in both fast transient and steady state), real-time monitoring of electrical networks, and the increasing exposure of engineering to multi-disciplinary environments. The recent formation of Study Committee C2: System Development and Economics, within the International Council on Large Electric Systems (CIGRE), is confirmation of the *increasing* need for engineering to include financial and economic evaluation within the future planning of projects – not to suggest that this was not present in the past. Study Committee C2 includes the following:

- PS1 - Challenges for asset management.
- PS2 - Challenges in the development of dynamic models.
- PS3 - Managing an acceptable reliability level in a changing electricity market.

Modern simulation software has enhanced the financial modeling techniques and accuracy thereof. Existing reliability studies include empirical planning rules, supply design standards, simplified cost-benefit analysis, detailed financial and economic evaluation [5.2 p137]. In view of the above, why has the researcher selected specific reliability indices which do not directly relate to previous studies? To answer the former consider the following:

The concept “adequacy “ within reliability is a complex issue and relates not only to the presence of an electrical waveform (COS) in terms of voltage and current, but also to the shape of the waveform (QOS). By reviewing some of the basics of QOS issues one grasps the complexity of deriving a single composite index for the measurement of reliability. Specific issues such as voltage unbalance will be discussed in more detail in a later section of this chapter. The most relevant issues according to the South African Rationalized User Specification NRS 048: Electricity Supply Quality of Supply (Part 2: Minimum standards) - For application by the National Electricity Regulator regarding QOS [5.3], are the following:

- Voltage unbalance: The compatibility level for unbalance on three-phase networks is 2 %. On networks where there is a predominance of single-phase or two-phase customers, the assessed unbalance may be up to 3 %. To be discussed later in more detail.

- Voltage regulation: Compatibility levels for voltage regulation are generally 10% for voltage up to and including 275kV and 5% for above 275kV.

- Frequency compatibility levels shall be 50 Hz, and the maximum deviation shall be: a) for grid networks: ± 2, 5 % at all times b) for islanded networks: ± 5, 0 % at all times, and ± 2, 5 % for 95 % of a one-week period.

- Harmonics and interharmonics: Where available, electromagnetic voltage transformers should be used up to the 25th harmonic *(see also annex A of*

NRS 048-5). Capacitive voltage transformers (CVT) may be used only where special techniques are applied. Under no circumstances should the (uncompensated) secondary output of the capacitive voltage transformer be used for the measurement. Where compensation techniques have been proved to meet the above accuracy requirements, the compensated CVT output signal may be used. High-voltage dividers and capacitive bushing tap-off techniques which meet the required accuracy may otherwise be used where electromagnetic voltage transformers are not available. A utility is responsible for enforcing limits on the injection of harmonics by its customers. Utilities should advise their customers to specify that the immunity of equipment used in new or upgraded plant be compatible with the harmonic compatibility levels defined in 4.1.1 of NRS 048-2. Where existing customers' installations cannot be operated within the maximum harmonic levels permitted in table 1 of NRS 048-2, then utilities should negotiate specific arrangements to provide reduced harmonic levels to the customers concerned. Where a utility installs capacitors, the installation as far as possible should be designed and operated so as to avoid resonances at dominant harmonic frequencies. The resonant frequencies of a network capacitor installation change with network configuration. Network operating states and contingencies should be considered when such designs are undertaken.

- Flicker: A utility is responsible for enforcing limits on the injection of flicker by its customers. Utilities should advise their customers to specify that the immunity of equipment used in new or upgraded plant be compatible with the flicker compatibility levels defined in 4.2.1 of NRS 048-2. Where existing customers' installations cannot be operated within the maximum flicker levels in 4.2.1 of NRS 048-2, then utilities should negotiate specific arrangements to provide reduced flicker levels to the customers. NOTE the effects of flicker are noticed only at the LV point of coupling (i.e. where lighting systems are connected). When this is considered, together with recent studies which show that flicker levels are reduced from HV to LV networks, it may result in utilities agreeing on higher P_{st} levels at HV connection points. The level of flicker reduction from the HV to LV point will differ from network to network and needs to be carefully assessed before flicker levels are established in a QOS contract.

- Voltage regulation: The guidelines for the calculation of voltage drop in distribution systems for residential areas, in NRS 034-1 should be followed, where applicable. In all cases, networks should be designed and operated to meet the requirements of clause 4.6 of NRS 048-2. In particular, utilities should ensure that their large customers have voltage regulation and power factor correction equipment that operates correctly, to avoid over or under voltages in a customer's network being transmitted to the utilities network. This is important not only to avoid other customers being affected by the abnormal voltage, but also to ensure that the life expectancy of plant, particularly transformers, is not reduced. (This can have a consequential effect on the QOS through forced interruptions due to premature plant failure.) For example, as can be the case with arc furnaces with switched capacitor banks, when the load is switched off, the capacitor banks voltage rises, causing the utility's transformer to be over-excited from the secondary windings. It is therefore essential that utilities ensure that where customers have capacitive compensation equipment installed, that the customer has also installed protection or control devices that will limit over-excitation of supply transformers to within their design parameters.

- Frequency: Most local utilities have no control over frequency. Generation capacity and transmission, operation and design should meet the load requirements. NOTE: Under-frequency load shedding will be by agreement between a utility and its customers, where practicable. In general, the generation authority will impose load shedding on the distributing utilities and will not often be possible to advise and obtain the agreement of customers.

- Voltage Dips: The sudden reduction in the r.m.s. voltage, for a period of between 20 ms and 3 s, of any or all of the phase voltages of a single-phase or a polyphase supply. The duration of a voltage dip is the time measured from the moment the r.m.s. voltage drops below 0,9 per unit of declared voltage to when the voltage rises above 0,9 per unit of declared voltage.

Reviewing the above minimum standards confirms that the researcher cannot derive single composite reliability measure indices which are inclusive of the above. To further complicate the issue, the above minimum standards are not the same in each country or utility. Returning to the original research objective, the proposed research reliability index is intended to be specific for a transmission network and not a distribution network. With reference to reliability there are few subtle, and yet other significant differences between transmission and distribution networks. Studying these differences will support the research direction towards a “transmission only” reliability index. These differences are listed and discussed as follows.

5.2.1 Number of directly connected customers.

Transmission networks do not have the magnitude of directly connected customers as in the case of distribution networks. Conventional international reliability measures make use of: System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), Customer Average Interruption Frequency Index (CAIFI), Customer Average Interruption Duration Index (CAIDI), System Average Restoration Index (SARI), and Delivery Point Unreliability Index (DPUI). The total number of points of delivery differs between transmission and distribution. Considering that approximately 80% of all interruptions experienced by customers are on distribution systems, the set limits and actual values differ significantly between the two networks.

5.2.2 Type of connected customer.

Customers connected to a transmission network are either large customers, or bulk power users. They are generally supplied at transmission voltages of 110 kV and above. The fact that these fewer connected customers are bulk users makes the impact of reliability supply more significant. Most of transmission’s directly connected customers are large and sensitive to quality of supply issues, e.g. raw material processing plants. Eskom (South Africa) customers connected to the transmission network are Alusaf and Richards Bay Minerals at Richards Bay in Natal. Depending on the economic portfolio within a country, a few large energy users can represent a relatively large percentage of the total energy sales. Such an example is Eskom where up to 32% of the total monthly energy is consumed by the ten largest customers (60,695GWh of 187,589GWh).

5.2.3 Global nature of transmission networks.

Transmission networks can be considered as “global” networks as they span across national and, in many cases, international boundaries transmitting bulk energy which is crucial for the economy of both consumer, electricity utility and government (from a tax collection point of view). This presents additional issues such as international trading, foreign currencies, Grid Network Codes (GNC), voltage and frequency limits, strict service level agreements (SLA’s) and possibly penalties for electrical energy not supplied (EENS). Reliability indices are used by regulators to monitor electricity utilities. Performance based on these indices is either penalized or rewarded. This is a regulatory movement towards performance based electricity rates [Ref: Reliability Indices – Tom Short]. Such penalties are also included in the utility costs for reliability.

The transmission system is being subjected to flows in magnitudes and directions that were not contemplated when it was designed or for which there is minimal operating experience. New flow patterns result in an increasing number of facilities being identified as limits to transfers, and transmission loading relief (TLR) procedures have been required in areas not previously subject to overloads to maintain the transmission facilities within operating limits [5.4 p19].

5.2.4 Differing technical performance.

Transmission and distribution experience different performance levels. What are the reasons for this difference? A fact generally disregarded is that overhead line performance is cyclic by nature, as illustrated in *Figure 5.2: Cyclic Nature of Overhead Line Performance* [5.5 p20]. The illustration is simplistic and does not intend to indicate that transmission line performance is sinusoidal or at regular intervals, but rather that there exists a cyclic nature that varies in amplitude and frequency. This cyclic phenomena is confirmed when reviewing actual field data of Eskom’s 400kV transmission line in *Figure 5.3: 400kV Transmission Line Faults –*

11 year period [5.6 p37] This in itself poses a challenge regarding business efforts to improve performance.

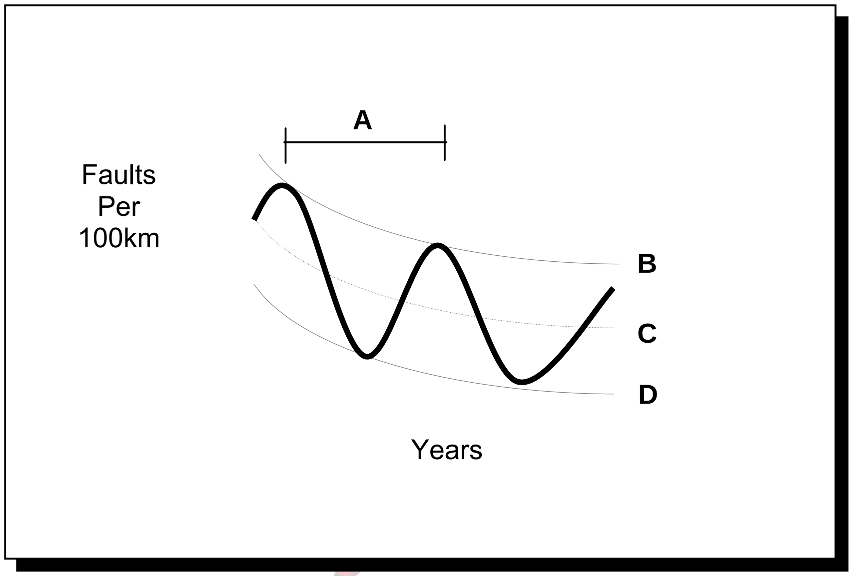


Figure 5.2: Cyclic Nature of Overhead Line Performance

During periods of poor performance (typically at the crest of the cycle: curve B) all efforts are concentrated on improving performance. Broad approach improvement initiatives are usually applied such as wildlife deterrents, servitude management, insulator replacement, increasing insulation creepage distances for pollution, insulation replacement from glass to composite materials such as silicon rubber, cyclo-aliphatic and EPDM, tower modifications, lowering tower footing resistances, increasing conductor jumper clearances, etc.

Unfortunately the fact that many of these initiatives are being applied simultaneously prevents the distribution or transmission line engineer from actually identifying the root cause of overhead line underperformance. Another factor to be considered is that these initiatives are normally applied during and just after a poor performance period of the performance cycle (curve B). This creates the false assumption that the improvement in performance towards curve D is due to the performance improvement initiatives.

Realistically, performance indicators should have annual revisions which accommodate the cyclic nature of transmission line performance and yet with time have an improving trend as depicted along curve C. This cyclic nature is evident during both short-term (seasonal) and medium-term (3-4 year) periods. This phenomenon can be attributed to a number of factors.

Firstly, rainfall patterns vary throughout any given year. Wet seasons are generally accompanied by high lightning activity, therefore increasing the probability of lightning related faults. Lightning activity in the early stages of the wet season can be expected to cause more faults due to the generally poorer overhead tower footing resistance. As the rain season extends itself, and soils become more saturated, it can be confidently assumed that the soil resistivity will become more favourable. However, the reduction in faults due to lightning as the wet season progresses is not always evident. This is attributed to the fact that in South Africa the lightning activity or frequency generally increases during the wet season. However, this observation is not always consistent.

Secondly, vegetation growth is abundant following good rainfall. Abundant vegetation forms excellent biomass in overhead line servitudes. If timeous servitude vegetation management is not practiced fires beneath overhead transmission lines can have a significant impact on performance. Effective servitude management practices must be strictly adhered to on transmission lines and in particular on lines with a high fault rating such as outgoing feeders from power stations. Not to be neglected is the pollution build-up effect certain bio-mass fires have on insulators. This is particularly apparent from fires raging across sugarcane-filled servitudes.

Thirdly, the conditions relating to rain and vegetation influence wildlife in the vicinity. Wildlife includes the various species of problematic birds – problematic from a point of having an adverse effect on overhead transmission lines. Large birds such as Herons and Vultures either pollute insulators from raised perched positions, or cause phase-to-earth flash-overs from “streamers” (a projected stream of conductive excreta).

This cyclic nature of transmission line performance is illustrated in *Figure 5.3: 400kV Transmission Line Faults - 11 Year Period.* The figure represents the performance (faults/100km/year) of Eskom's 400kV transmission network over a period from 1991 to 2002. The bars depict monthly performance data and the points, the 12-month moving average. The solid line represents the annual revised performance limits. Information was sourced from Eskom Transmission Technical Monthly Reports – January 2003.

400 kV Transmission Line Faults / 100 km

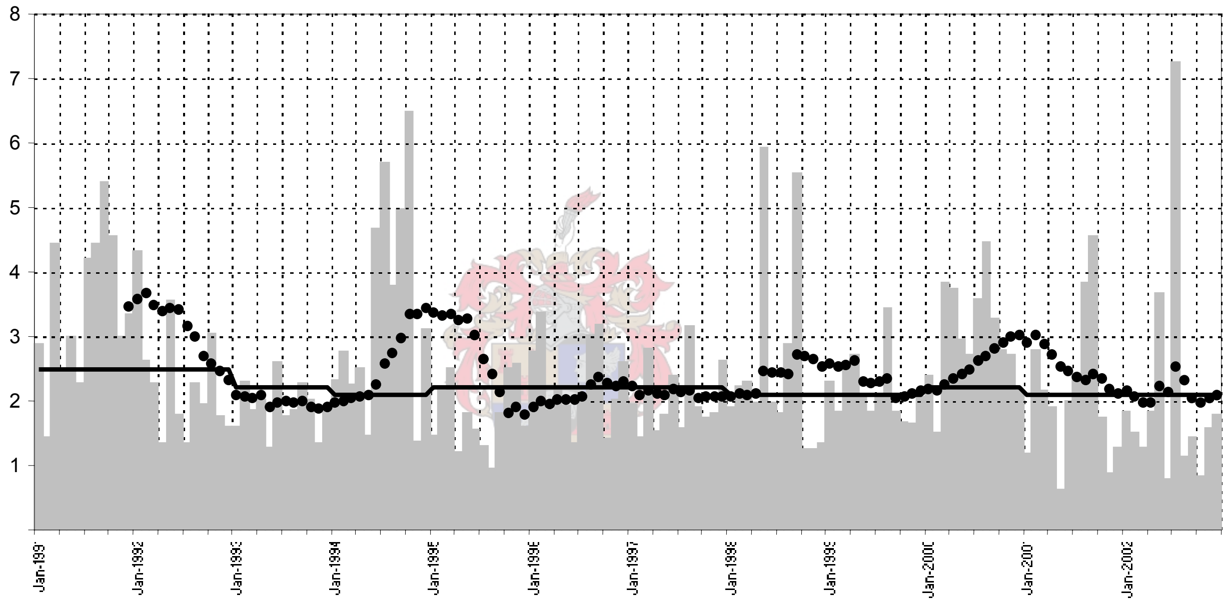


Figure 5.3: 400kV Transmission Line Faults – 11 Year Period.

It can be reasonably expected that from an *electrical performance* point of view the number of faults per 100km is inversely proportional to the nominal system voltage. This assumption is based on the fact that the higher the nominal system voltage the lower the incidence of faults due to lightning (whether the strikes are direct or indirect). With a uniform lightning density (lightning flashes/km^2/year), the probability of flashover reduces with a higher basic insulation level (BIL). This is illustrated in *Figure 5.4(a) Overhead transmission line faults as a function of system voltage* [5.5 p20]. The figure depicts a typical function between the faults per 100km and the system voltage without representing any accurate graphical scale.

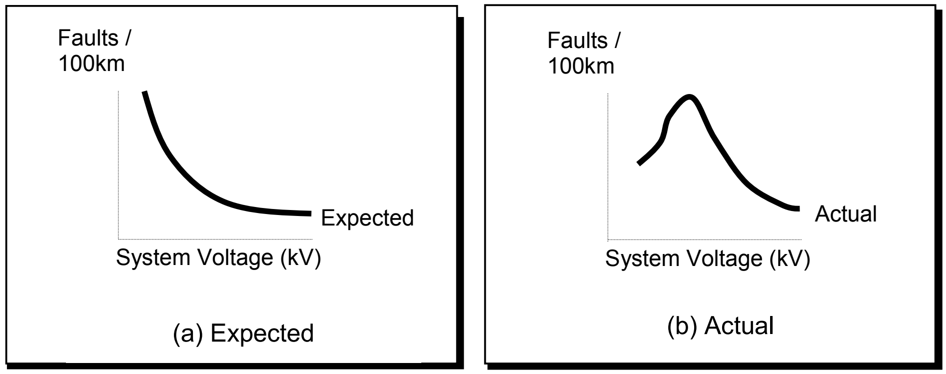


Figure 5.4: Overhead Transmission Line Faults as a Function of System Voltage

This pattern of expected number of faults is however not witnessed from field reports. A particular trend within Eskom is depicted in Figure 5.4(b) [5.5 p21].

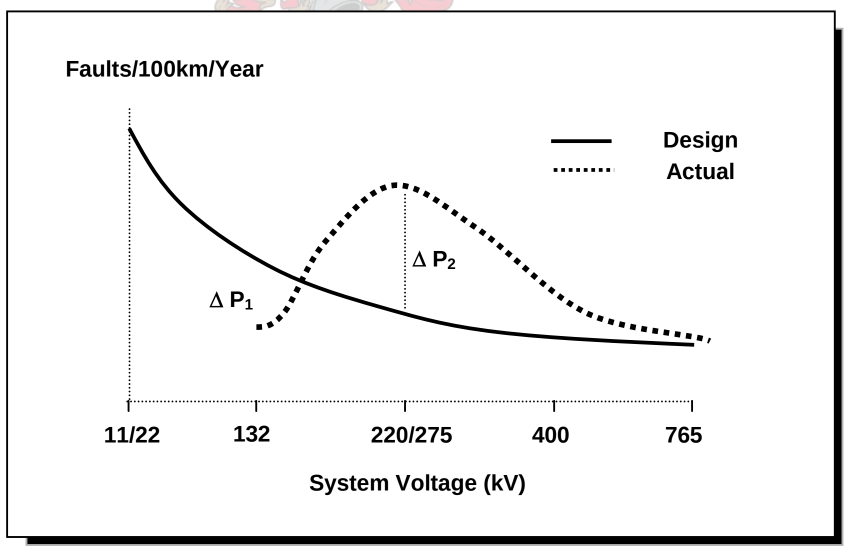


Figure 5.5: Combined Actual Versus Expected Transmission Overhead Line Faults/100km/year as a Function of System Voltage

Actual measured performance on transmission networks however indicates very different overhead line performance characteristics.

Consider the following cases as illustrated in *Figure 5.5: Combined Actual Versus Expected Transmission Overhead Line Faults/100km/Year as A Function of System Voltage* [5.5 p22].

This indicates that both the 132kV & 220/275kV system voltages do not follow performance expectations. Reviewing Figure 5.5: the 132kV overhead transmission lines have performed *better* than the expected performance level (ΔP_1). However the 220/275kV overhead transmission lines have performed *significantly worse* than the expected performance level (ΔP_2).

Possible explanations of the above may be that on closer investigation the 220/275kV overhead transmission lines were found to span across geographical areas of higher lightning flash densities. Furthermore these transmission lines are located in areas with higher environmental risk exposure such as vegetation fires and bird pollution. Initial design parameters have also contributed towards the poorer performance. These include under sizing of tower window size, under-insulation from a pollution point of view and low insulator creepage distance. The 400kV lines are also under-insulated from a pollution point of view.

This performance behaviour is not only unique to Eskom. Consider a summary of the historical performance statistics of transmission outages in Alberta in Canada – an environment with different vegetation and extreme climatic conditions. *Table 5.1: Alberta Transmission Outage Statistics* reveals that the actual frequency per 100km (faults/100km per year) is different than the expected performance based on the predicted BIL electrical design. One would expect the 500kV system to be the best performer. However, from the available data the 500kV system is the worst performer.

Table 5.1: Alberta Transmission Outage Statistics

Alberta Interconnected Electric System **Transmission Outage Statistics** **Summary for Line Related Forced Outages** **For the Period From 1995 – 1999**								
Voltage Class (kV)	Kilometer Years (km.a)	Number of Sustained Faults	Frequency per 100km.a (faults/100 km.a)	Total Outage Duration (hours)	Average Outage Duration (hrs/faults)	Unavailability Per 100km.a (%)	Number of Momentary Faults	Frequency per 100km.a (faults/100km.a)
69/72	11590	297	2.56	1516	5.10	0.15%	262	2.26
138/144	57248	423	0.74	3441	8.13	0.07%	668	1.17
240	36517	299	0.82	1652	5.53	0.05%	305	0.84
500	1596	15	0.94	34	2.27	0.02%	107	6.70
Total	106951	1034	0.97	6643	6.42	0.07%	1342	1.25

Source: CEA

What is apparent from the former is that the performance of overhead transmission lines is not solely dependent or predictable on the selection of electrical design parameters. It will be witnessed later that environmental factors play a significant role. The”unexplained” categories of faults also contribute significantly to the above deviations in performance. The better than expected performance of the 132kV lines reveals that these lines span across environmentally friendly terrain and the insulation specific creepage distance (mm/kV) is larger than what is required.

Utilities categorise their transmission overhead line faults in different ways. Some are exhaustive in their categorisation and others restrict themselves to the most significant categories. Neglecting their order of contribution to aggregate faults the main categories can be classified as mechanical, electrical and environmental.

Mechanical faults:

- Public contact such as vehicles or unauthorised climbing of towers.
- Mechanical failure of conductor, overhead shielding wires, insulators or equipment hardware.

Electrical faults:

- Bird pollution or “streamers”.
- Pollution due to saline conditions, industrial or light wetting.
- Design constraints such as under-dimensioned tower size.
- Malfunctions of protective relays.
- Human operating errors caused by live maintenance practices or closure on portable earths.
- Neighbouring or supplying utility error or outage.

Environmental faults:

- Vegetation growth within servitude’s such as trees or shrubs causing flashovers.
- Fire-grass, sugarcane and reeds.
- Lightning flashovers.
- Severe weather conditions such as ice, snow or wind causing mechanical failure or flying debris causing electrical faults.
- Vandalism such as gun shots and stone throwing.
- Terrorist activities such as explosives or dismantling of pylons.

Unknown causes for faults are relevant to all three main categories. It is essential to categorise and rank faults so resources can be applied to correct these faults within a framework of direction for the improvement of transmission overhead line performance in an optimal way. In recent years the reliability on the reporting of operational performance has improved. This is due to many factors. These include advancement in software programmes, national or state regulators insisting on performance results, competition and operator training and awareness.

Regulator requirements are increasingly stating that the transmission and distribution system should be optimized from a socio-economic point of view taking into account investment costs, costs of electrical losses, operation & maintenance costs and interruption costs. Lack of reliable performance data and the lack of data exchange between utilities and customers can be a problem when the arrangement of financial compensation for electrical energy not supplied (EENS) is applied through supply level agreements. The total process of EENS involves performance information between systems like customer, network, fault and interruption and SCADA information systems. Such an example is the Norwegian distributor companies. From year 1997 they were regulated by an income cap model. In order to increase the cost-effectiveness in the transmission and distribution monopoly, the electricity utilities were instructed to reduce their total costs by 1, 5 – 4, 5 % per year throughout the year 2001 [5.6]. This pressure drove the refurbishment of their performance management.

5.2.5 Diversity of customer reliability expectations.

Customer reliability expectations are more diverse at distribution networks than for transmission networks. Consider the difference between an industrial consumer and the same electricity network supplying a domestic residence.

The above considerations need detailed explanation as it is from this reasoning that the researcher has pursued this section of the study. Current available reliability indices focus on measuring reliability at the final element of production, i.e. the product in the form of its continuity and quality. This has been discussed in *Chapter 1: Background*. The product reliability is a function of both plant and equipment, and operations and maintenance reliability.

Traditional cost-benefit analysis of reliability assessment has focused on value based assessment which includes the affordability criteria for both the utility and the customer. These analyses have assisted planners in prioritising transmission expansion or refurbishment projects. This can be represented by *Figure 5.6: Cost-benefit Analysis of Reliability.*

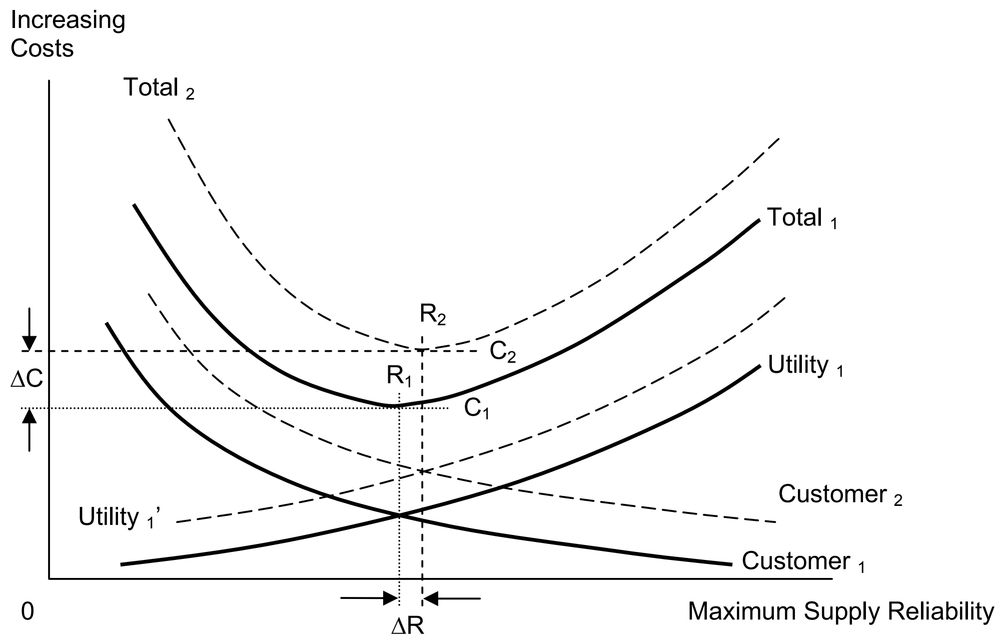


Figure 5.6: Cost-Benefit Analysis of Reliability

Consider the cost-benefit curves, $Customer_1$ and $Utility_1$. The customer curve represents the inverse relation of the electrical energy not supplied (EENS) as a function of an increase in reliability. Higher network fault incidents cause customer outages resulting in higher costs. Many researchers have termed these costs, the "social costs" in terms of financial and economic terms [5.4 p123]. They are a function of the frequency and duration of momentary (auto reclose operation) and sustained (system minutes) interruptions and differ with each customer. Other than EENS, customer costs include the customers' perception of "customer value of service" [5.3 p1594]. Unbalanced voltages cause reductions in induction motor efficiency and heating effects which ultimately result in premature ageing and failure of motors. Motors are derated according to the voltage imbalance. NEMA Standard MG 1-1993: Motors and Generators have produced a derating graph and table for induction motors based upon percent of voltage unbalance. For motors up to 500 horse power (HP), the typical values are illustrated in *Table 5.2: (Derating Table For Induction Motors Based Upon Percent of Voltage Unbalance. NEMA Standard MG 1-1993: Motors and Generators).*

Table 5.2: (Derating Table For Induction Motors Based Upon Percent of Voltage Unbalance. NEMA Standard MG 1-1993: Motors and Generators)

Voltage Unbalance	Approximate Derating
1%	None
2%	95%
3%	88%
4%	82%
5%	75%

Furthermore, included in these costs should be the customer's effort to install the minimum level of QOS mitigation practices to his own plant and equipment. Typically, voltage unbalance can be mitigated by properly sizing ac-line and dc-link reactors on adjustable speed drives (ASD). In addition relay selection, setting and application will reduce the effects of voltage unbalance. The application of the former will depend on the size, loading, insulation class and service factor [5.10]. Depending on system and load configurations, negative sequence current relays have been found to more reliable than negative sequence voltage relays [5.11].

The time and day that interruptions occur will also have an effect on the customer cost curve. The problem of fairly classifying operating days into normal days and major event days on the basis of distribution reliability is one that is becoming more important as regulators increase scrutiny of, and impose limits on, operating reliability. Statistical classification of major reliability event days in distribution systems [5.20]. IEEE User Guide P1366 [5.21] defines "a Major Event" as: "Designates a catastrophic event which exceeds reasonable design or operational limits of the electric power system and during which at least 10% of the customers within an operating area experience a sustained interruption during a 24-hour period." The significance of the "10% of the customers" comes into perspective when comparing transmission and distribution networks. The impact of one fallen transmission tower can contribute to 10% and higher of customer outages. However, the time to repair the single transmission tower may be significantly lower than a major event causing 10% customer outage on a distribution network.

There are significant differences in the type of reliability reporting due to location and size differences in utilities, as well as differences in reporting requirements across borders which a single utility may span. Also, though utilities generally agree on definitions of several reliability indices, differences in how the utilities get the information that goes into these indices, makes the results different enough that comparisons are still difficult. Other than data collection instrumentation, some of the specific differences are:

- whether storm-related outages are included or excluded;
- whether or not planned outages are included;
- definition of the minimum length of a sustained outage (with 1, 2, 3, or 5 minutes all being used);
- definition of when an outage begins and ends;
- differences in the accuracy, timeliness, and thoroughness of reporting—especially for large outages in bad weather.

Furthermore, performance definitions are also not conclusive within the international organisation. An example is the assessed versus the compatibility level. The assessed level is the level used to evaluate the measured values at a particular site against the compatibility levels. The assessment criteria require both the measurement instrument to be defined, and a statistical criterion to be applied to the measured data points. The compatibility level (electromagnetic compatibility level) is the specified disturbance level at which an acceptable, high probability of electromagnetic compatibility should exist. [IEC 161-03-10/A]. The compatibility level for unbalance on three-phase networks is 2 %. On networks where there is a predominance of single-phase or two-phase customers, the assessed unbalance may be up to 3 %.

“Social costs” may also include taxes to finance government owned electricity utilities.

The electricity utility curve $Utility_1$, represents the increasing cost for the refurbishment, expansion, operational costs, loss of sales and possibly consequential costs for the violations of service level agreements (SLA's). This increase in cost is to provide an improvement in reliability by attending to the former issues. Included in operational costs are power quality issues such as voltage unbalance and the application of mitigation techniques. Because distribution networks are at the customer "coal face", it is important that they balance loads as these are the main cause of unbalanced voltages [5.5]. There are no real operational costs involved in this regard as distribution systems can be balanced by reconfiguring the system through manual and automatic feeder switching operations. Reconfiguring to reduce transfer losses also has the effect of balancing loads [5.6] Unbalanced impedances are generally the second largest contributor to unbalanced voltages [5.7]. Extension research has been undertaken regarding the former of which significant contributions have been forthcoming from the American National Standards Institute (ANSI) Standard C84.1-1995, IEEE Std. 141-1993.

Curve Total $_1$ is the sum of curve "$Customer_1$" and "$Utility_1$". The optimal affordability condition is at the intersection of both curves which is at the minimum position of the sum curve Total $_1$, at R_1 and C_1. From a voltage unbalance viewpoint, the annual incremental cost to the customer for various percent voltage unbalance limits varies between 1% to 3% [5.8 p3-1]. NEMA MGI-1993 recommends motor derating in the presence of voltage unbalance of greater than 1%. ANSI C84.1-1995 allows a 3% voltage unbalance. At 3% the standard states that the cost to the customer is minimised. Of interest are the findings of the Canadian Electrical Association (CAE). Older design techniques, with the absence of modern simulation software, produced motor and equipment designs which allowed higher disturbance levels than current designs. Today there is pressure from motor manufacturers to demand for supply quality with lower voltage disturbance levels.

Consider another customer ($Customer_2$), connected to the same utility demanding a higher reliability at R_2. It is assumed that the higher expected reliability demanded is accompanied with a higher customer cost curve -

justifying the upward displacement of the customer cost curve from $Customer_1$ to $Customer_2$. To achieve this higher level of reliability the electricity utility would incur additional costs as illustrated in a shift of the curve to $Utility_2$. It can be reasonably assumed that the expected higher reliability would result in an upward shift in the utility cost curve to $Utility_2$. The direction of the upward shift is also dependent on the required reliability level. A customer with a lower reliability requirement will be represented by a shift to the left. An important aspect regarding the shift of the customer curve is the following: A higher customer reliability requirement does not necessarily mean a customer curve movement upwards and a shift to the right. For the *same* customer requiring a higher reliability it can be reasonably assumed that the customer curve will move upwards and shift to the right. However, it is possible that certain customers may require a high reliability supply, but at low customer or "social " costs relative to other customers. Similarly, certain customers may require a low reliability supply, but at high customer or "social" costs relative to other customers.

In the case of distribution networks, numerous customers are connected either directly or indirectly to distribution points of supply. Distribution substations are more susceptible to QOS issues than what transmission substations are. These issues include ferro-resonance where non-linear reactance is present, harmonics, flicker, load curtailment and voltage regulation. Due to the numerous and diverse customer reliability requirements at distribution level, customer and utility costs can be represented by numerous total costs curves. Remembering that these curves have differing shapes and positions, it is realistic to graphically represent them as in *Figure 5.7: Diversity of Distribution Reliability Cost-Benefit Curves.* Each curve represents the total cost curve for reliability at different distribution points of supply (POS_1 to POS_9). The particular distribution network illustrated has 9 substations (points of supply). POS_1, POS_5 and POS_6 illustrate the various costs and reliability for each POS although within the same distribution network.

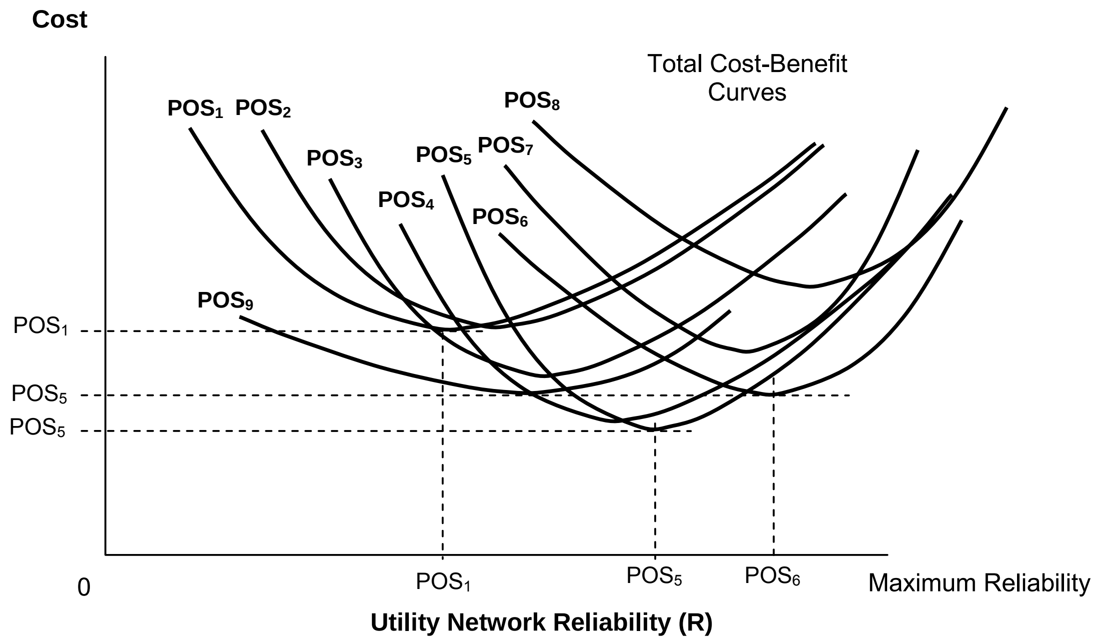


Figure 5.7: Diversity of Distribution Reliability Cost-Benefit Curves.

Other than what electricity regulators demand, it would be ideal that utilities provide electricity supply at the level of their highest demanding customer. Unfortunately due to economic reasons this is not practical so utilities provide supply at a reliability level which is affordable. Consider a distribution substation supplying a diverse customer base. If supply is provided accordingly to the highest QOS demanding customer, then the remaining customers supplied from the same network benefit from the higher QOS. Do they pay a higher tariff for this higher QOS or does the single customer with the highest QOS demand pay the higher premium? This has to be evaluated separately as the higher QOS demanding customer could be a large energy consuming customer who benefits more than the remaining customers by being supplied at a reduced tariff!

How does this relate to transmission networks? As large or bulk electricity transmitters, transmission networks have less diverse customers. In other words the graphical illustration may be simpler than in Figure 5.7: Diversity of distribution reliability cost-benefit curves. For simplicity the total cost-benefit curves are assumed to be uniform in shape. In reality these curves will vary. Of interest is that the customer damage function curves of

Chowdhury and Koval produce virtually the same slopes at four separate substations with different customer mixes [5.2 p1594].. The mix of customers varies from 26.51-94.74% for large users; 1.31-13.75% for industrial; 0.31-21.79% for commercial; and 0.00-27.33% (residential). Although each substation had different estimated interruption costs, the slopes as a function of the interruption duration were similar. These findings may question the researcher's hypothesis of numerous different slopes of cost-benefit analysis curves as illustrated in Figure 5.7: Diversity of distribution reliability cost-benefit curves? What was not however presented in the findings was the individual EENS for each customer mix.

The researcher will continue to assume the diversity in reliability between transmission and distribution and provide initiative for further research in the field of cost-benefit analysis. As reliability is considered a variable in the total researched network utilisation index, it is deemed appropriate that theory of such a nature stimulate the interest of national electricity regulators. The development of such theory could provide electricity utility network planning guidelines. In addition electricity regulators could justify and support realistic tariff revisions. For simplicity the following are assumed as a base for further investigation.

- Consider a transmission network supplying 5 customers with varying reliability scenarios.
- Assume that each of their total cost-benefit curves have the same shape and slope.
- Each customer has different customer or "social" costs.
- Each cost-benefit curve is equally spaced from the lower order curve/s.

This study only conceptualises the basics and the benefits of this extended cost-benefit theory. To gain benefit from this, the challenge would be to realistically quantify the cost-benefit curves. It must, however, be noted that these derived curves would be subjective and speculative as a percentage of the quantitative analysis is based on customer perceptions on the value of services. There are three cost-benefit scenarios to be considered.

5.2.5 (a) *<u>Uniform rate of change cost-benefit scenario</u>.*

Modern technology in industrial plants and competitive markets has resulted in increasing customer demand for improved reliability. Additional costs are incurred to improve this reliability, therefore shifting the customer curve to position "Customer $_2$". The cost to utilities to meet these customer expectations has resulted in a similar shift in the utility curve to "Utility $_2$". The result is a new "Utility $_2$" curve with optimal positions at R_2 and C_2. This change in recent customer reliability expectations ΔR has resulted in a cost change of ΔC. The relationship between the rate of change between reliability and costs (ΔC/ΔR) is potential for further research.

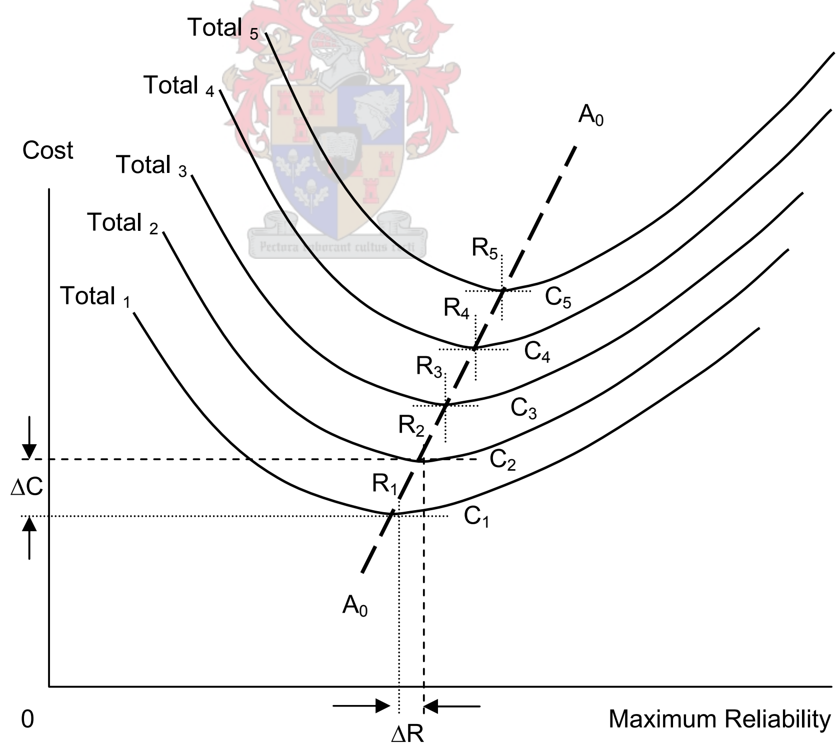


Figure 5.8: Rate of Change of ΔR/ ΔC – Uniform Rate

This is represented in *Figure 5.8: Rate of Change of ΔC/ΔR – Uniform Rate.* Consider numerous scenarios of total cost curves (Total $_{1\ to\ 5}$). $\Delta C/\Delta R$ is illustrated at a uniform rate between all five total cost curves. This could be applied for facilitating the future projection of transmission network expansion and customer reliability expectations. However the assumption of a uniform $\Delta C/\Delta R$ is possibly unrealistic and alternative scenarios are represented in Figures 5.9 and 5.10.

5.2.5 (b) *Increasing rate of change cost-benefit scenario*.

Consider the line A_1. A_1 represents the intersection of all the minimum points of the aggregated costs for graphs Total $_{1\text{-}5}$. Initially the slope of A1 from curve "Total $_1$" to "Total $_2$" is small relative to the higher valued curves (Total $_{3\text{-}5}$). At this initial stage, the slope is sensitive to both cost and reliability. They are dependent on each other. This initial cost dependency can be considered from three points of view.

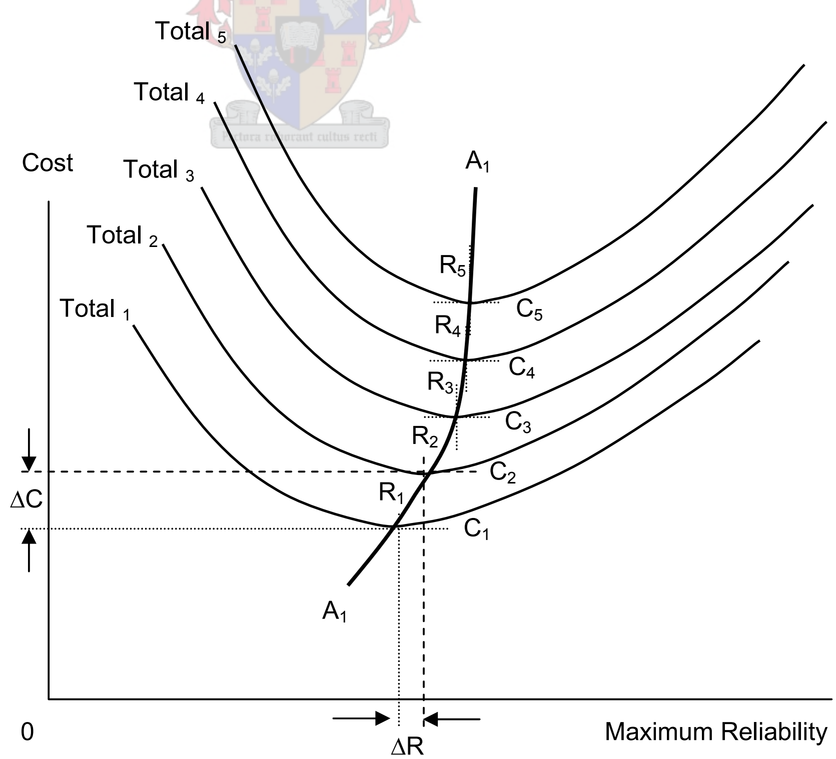


Figure 5.9: Rate of Change of $\Delta C/\Delta R$ – Increasing Rate.

Firstly, from an electric utility point of view, this is representative of the early stages of upgrading or expanding on an existing transmission network to provide an improved level of reliability. The costs to the electric utility are high. During this initial period it may be necessary to upgrade the energy transfer capability of the network. Voltage regulation may be compensated by the installation of reactors, capacitors or static var compensators (SVC's). Reconfiguring substation operational layouts may also be an option. Utility costs could be significantly high relative to customer costs. In fact, during this period customer costs, other than the EENS, may be negligent. Secondly, during this period customer costs and utility costs may be high. Customer costs for the mitigation of quality of supply and utility costs as previously explained. Thirdly, utility costs may be insignificant compared to customer costs.

5.2.5 (c) *Decreasing rate of change cost-benefit scenario.*

Consider *Figure 5.10: Rate of Change of ∆C/ ∆R - Decreasing Rate.* The initial slope of line A_2 (∆C/ ∆R) is relatively large between C_1R_1 and C_2R_2 when comparing to slope of the line between C_4R_4 and C_5R_5. Between C_1R_1 and C_2R_2 both cost and reliability are dependent. However, proceeding further from R_1 along A_2 , the slope (∆C/ ∆R) decreases.

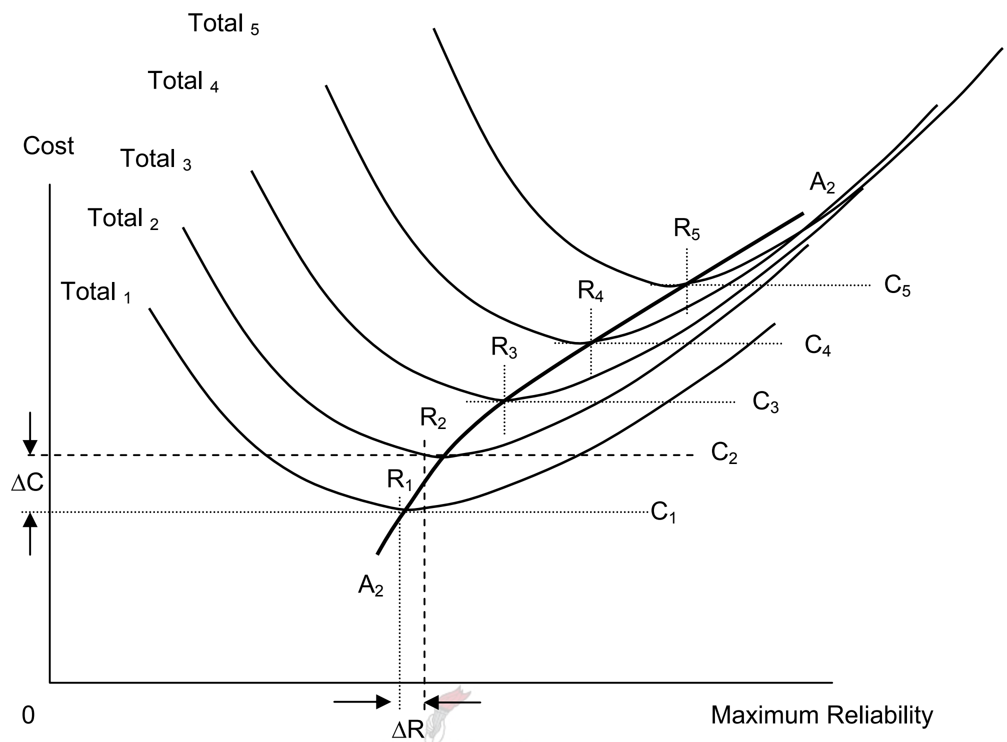


Figure 5.10: Rate of Change of ∆C/ ∆R - Decreasing Rate

This would represent a condition where customer reliability requirements change at an accelerated rate (∆R increases) while total cost increases proportionately (∆C is constant). Under what condition is this evident? A customer introducing new technology such as thyristor and microprocessor controlled equipment, accompanied with spare operating and infra-structure capacity on the transmission network could witness such a condition. How? Existing inherency and redundancy on the transmission network would not incur additional utility costs. The only increase in costs would be the "social" cost to the customer for procuring new technology. This can also be argued against in that the introduction of such technology will result in production savings to the customer. However, new technology can be accompanied with higher production turnover making a supply interruption more significant –

higher production losses during the same outage time with older technology.

Not shown, an unrealistic condition would be realised where $\Delta C / \Delta R = 0$. This would represent a condition where an increase in reliability would have no effect on the total costs. Such a condition would be impossible as costs would be incurred by a competitive electric utility for any increase in reliability. Redundancy is a scarce commodity of the present day electric utility. One of the reasons is the “identification of requirement” to “commissioning” time of generation. Small “pebble-bed” type generation can be made available in the short-term planning horizon. This period can be shorter than the planning and construction of transmission networks. Often the major delay in transmission line planning and construction is obtaining servitude rights. Environmental assessment impact studies are a further consideration.

The statement that transmission and distribution should be viewed differently regarding reliability indices can be summarised as follows: The researcher’s personal belief is that reliability demands (both from a continuity and a quality point of view), will increase across a more diverse customer base and not be limited mainly to industrial customers. This is accompanied by the further belief that the future expectations regarding reliability of transmission networks will achieve stability within the short-term, while the demands for improved reliability will increase for distribution networks. The former can only be assumed in the presence of acceptable load-carrying capacity on transmission networks. This statement is supported by the fact that approximately 80% of all interruptions experienced by customers are on distribution systems.

The former assumes therefore, that unique reliability measurement indices are justified for the measurement of transmission network utilization.

Pursuing along the road of transmission reliability, it must be acknowledged that reliability is a keyword with varying foci. Focusing on quality of supply, voltage stability is possibly the single most important factor that affects all customers – whether industrial bulk energy users or domestic customers. When voltage stability margins are violated, load shedding or curtailment is inevitable, thus developing into a continuity of supply issue. Furthermore, it is difficult to accommodate quality of supply reliability indices into a composite transmission network utilization measure as these measures vary between customers as well as between utilities. Numerous papers have been published regarding this issue and referred to in Chapter 2: Research Literature.

The intent of this research was to include both the quality of supply, and continuity of supply component of Transmission Network Reliability (*R*). The research is limited to only four secondary variables which would be reduced to only a single most important secondary variable by means of factor analysis. The question: why only one secondary variable in the end? The inclusion of more than one would dilute the validity of such a study. An analogy would be the mixing of a fruit drink. Initially the fruits are identifiable in both taste and sight, but after liquidizing they are neither (the researcher does not jest by comparing the fruits of nourishment with the fruits derived from research).

The common factor of all four secondary variables within this group is *reliability* and consists of the following:

- System minutes / maximum demand (MW) [R_1].
- System minutes / total MWh [R_2] .
- Number of interruptions / maximum demand (MW) [R_3].
- Number of interruptions / total MWh [R_4].

On closer observation it becomes apparent that within the four selected variables, there are both continuity and quality of supply measures. System minutes (SM) is a measure of continuity of supply, and number of interruptions is a measure of quality of supply. Why then maximum demand and total energy? Consider the planning of transmission networks. The maximum challenge for any electricity utility is to meet maximum demands without load curtailment. An analogy is the design of a freeway. The freeway is designed to accommodate the expected peak traffic in a specific area. The fact that few motorists are on the freeway during after hours or off-peak periods, does not have an influence on the peak traffic design criteria. However, the total number of vehicles travelling over a period of time does have an influence of the operations and maintenance of the freeway.

The selection of number of interruptions/maximum demand gives an electricity utility an indication of the quality of supply in relation to maximum demand. This measure has the advantage that when benchmarking various utilities, the maximum demand is a normalising measure. Similarly, system minutes/total energy provides an indication of the continuity of supply in relation to the total energy sales. Again, this measure provides a normalising measure.

The total energy (MWh) per annum provides an indication of the size of the utility and a reflection of the production assets needed.

5.3 Input Data

The input data for the measurement of the above identified reliability indices are:

- Unsupplied Energy – measured in System Minutes (SM) and defined as the MWh unsupplied divided by MW peak demand (multiplied by 60 to convert into system minutes). It is a measure of continuity of supply.
- Maximum Demand – measured in Megawatts (MW) and defined as annual peak demand.
- Number of interruptions – measured in units, are faults which have resulted in the loss of energy supply and/or the automatic opening and reclosure of a supply circuit breaker.
- Total Energy Demanded – measured in Megawatt-hours (MWh) and defined as total annual MWh delivered from the transmission network.

The data under investigation is tabulated in *Table 5.2: Transmission Reliability Raw Data.*

Table 5.2: Transmission Reliability Raw Data.

Utilities	Max. Dmnd	MWh loss	Total MWh	Tx. Line length	Number of Trfrs.	System Minutes	No. of Interrupt.
E1	2313	316331.8	10488013	5545.25	96	8.84	41
E2	4822	124697	27710376	9203	114	1.78	122
E3	5250	797000	29281000	5707	112	3.70	207
E4	5309	701310	32702395	4024	261	2.54	109
E5	5421	1648839	31214479	9331	116	2.00	926
E6	5678	1469000	33610000	16123	531	6.08	353
E7	6213	1702244	37827636	6539	156	1.87	72
E8	6920	6,768	40964756	6663	147	4.00	65
E9	7422	1677968	43348860	7132	36	55.00	436
E10	9769	1420403	31564500	7443	35	95.83	459
E11	10624	1730250	57259959	12023	158	0.89	65
E12	11083	750000	68550000	11446	81	1.50	280
E13	13891	3194607	65719129	9534	928	4.88	303
E14	15993	4327759	91689803	9580	466	5.72	150
E15	16132	6553397	139433986	23872.2	1123	5.63	840
E16	17166	1700000	114750000	8683	143	2.71	198
E17	22764	4775320	141660000	29155	743	9.30	862
E18	23253	1736645	143692500	12628	158	34.37	316
E19	23309	2366666	139000000	15223	26	0.43	226
E20	26557	2248400	157947589	18174	222	0.07	666
E21	27447	4737104	170619400	26460	432	6.03	1457
E22	48305	5241500	283807400	14378.6	763	0.20	293

The performance measures for reliability are the following:

- System minutes / maximum demand (MW) [R_1].
- System minutes / total MWh [R_2] .
- Number of interruptions / maximum demand (MW) [R_3].
- Number of interruptions / total MWh [R_4].

The initial raw data is processed according to the above reliability performance measures and represented in *Table 5.3: Raw Data Processed Without Masking the Outliers.*

Table 5.3: Raw Data Processed Without Masking the Outliers.

Utilities	R_1	R_2	R_3	R_4
E1	8.4252E-07	0.41711375	0.0177259	3.909E-06
E2	0.00036893	6.42E-08	0.0253007	4.403E-06
E3	0.00070476	1.2636E-07	0.0394286	7.069E-06
E4	0.00047749	7.7517E-08	0.0205312	3.333E-06
E5	0.00036894	6.4073E-08	0.1708172	2.967E-05
E6	0.00107055	1.8086E-07	0.0621698	1.05E-05
E7	0.00030018	4.9303E-08	0.0115886	1.903E-06
E8	0.00057803	9.7645E-08	0.0093931	1.587E-06
E9	0.0074104	1.2688E-06	0.0587443	1.006E-05
E10	0.0098096	3.036E-06	0.0469854	1.454E-05
E11	8.3319E-05	1.5459E-08	0.0061182	1.135E-06
E12	0.00013534	2.1882E-08	0.0252639	4.085E-06
E13	0.00035123	7.424E-08	0.0218127	4.611E-06
E14	0.00035766	6.2384E-08	0.0093791	1.636E-06
E15	0.00034906	4.0385E-08	0.0520704	6.024E-06
E16	0.00015768	2.3588E-08	0.0115344	1.725E-06
E17	0.00040837	6.5623E-08	0.0378668	6.085E-06
E18	0.00147793	2.3917E-07	0.0135896	2.199E-06
E19	1.8517E-05	3.1052E-09	0.0096958	1.626E-06
E20	2.7361E-06	4.6005E-10	0.0250781	4.217E-06
E21	3.5316E-08	3.5316E-08	0.0530841	8.539E-06
E22	7.0243E-10	3.35950182	0.0060656	1.032E-06

On closer observation it becomes clear that the data above contains a number of outliers which, if not masked, will distort the final results. A simple box plot was performed to identify and exclude the outliers. This is illustrated in *Figure 5.11: Box Plot for R_3 values.* A summary of the masked outliers is presented in *Table 5.4: Summary of Box Plot R Values.*

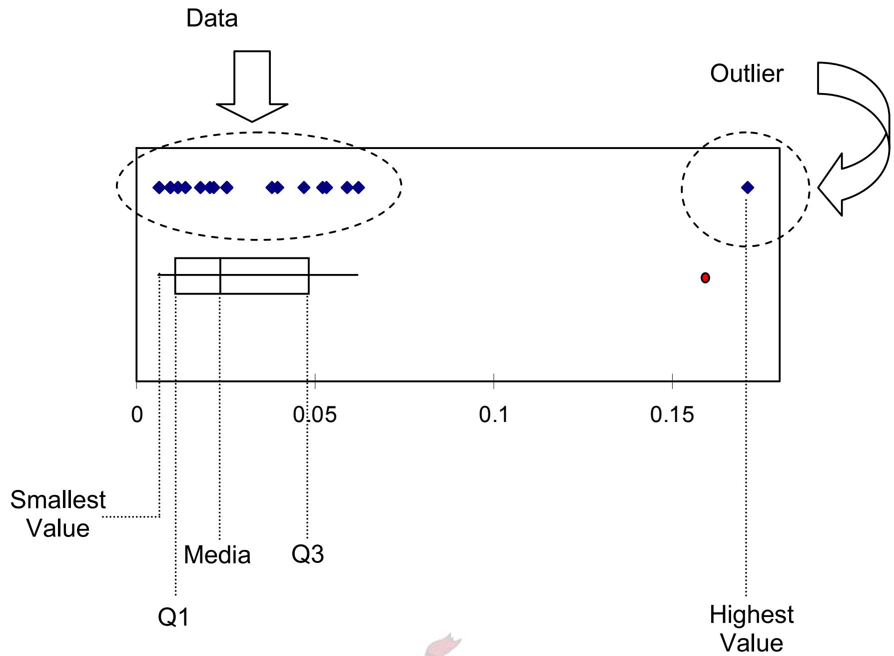


Figure 5.11: Box Plot for R_3 Values

Table 5.4: Summary of Box Plot R Values.

	R_1	R_2	R_3	R_4
Smallest Value	7.02432E-10	4.60045E-10	0.006066	0.000001032
Q1	6.71188E-05	3.23838E-08	0.0110745	0.0000016335
Median Value	3.54445E-04	6.49115E-08	0.0234455	0.000003997
Q3	6.09716E-04	1.95433E-07	0.04825625	0.0000074365
Largest Value	9.809601E-04	0.41711	0.170817	0.00002967
IQR	5.42597E-04	1.63049E-07	0.03718175	0.000005803
Outliers	**9.80960E-03** **7.41040E-03** **1.47792E-03**	**0.41711** **3.35950** **3.03600E-06** **1.26877E-06**	**0.170817**	**0.00002967**

It can be observed that R2 has the largest number and range of outliers. Utilities E9 and E10 had large discrepancies in both R1 and R2 variables. The reason for this large discrepancy is the abnormally high system minutes (SM) in both cases, namely 55.00 and 95.83 respectively. To complete the data matrix for both the principal component analysis and the factor analysis, the outliers were replaced with the median values. These revised values are presented in *Table 5.5: Raw Data Processed With Outlier Elimination.* The values which are documented in bold italics have replaced the previous outliers.

Table 5.5: Raw Data Processed With Outlier Masking.

Utilities	R_1	R_2	R_3	R_4
E1	8.4252E-07	***6.4912E-08***	0.0177259	3.909E-06
E2	0.00036893	6.42E-08	0.0253007	4.403E-06
E3	0.00070476	1.2636E-07	0.0394286	7.069E-06
E4	0.00047749	7.7517E-08	0.0205312	3.333E-06
E5	0.00036894	6.4073E-08	***0.0234455***	***0.000003997***
E6	0.00107055	1.8086E-07	0.0621698	1.05E-05
E7	0.00030018	4.9303E-08	0.0115886	1.903E-06
E8	0.00057803	9.7645E-08	0.0093931	1.587E-06
E9	***3.5444E-04***	***6.4912E-08***	0.0587443	1.006E-05
E10	***3.5444E-04***	***6.4912E-08***	0.0469854	1.454E-05
E11	8.3319E-05	1.5459E-08	0.0061182	1.135E-06
E12	0.00013534	2.1882E-08	0.0252639	4.085E-06
E13	0.00035123	7.424E-08	0.0218127	4.611E-06
E14	0.00035766	6.2384E-08	0.0093791	1.636E-06
E15	0.00034906	4.0385E-08	0.0520704	6.024E-06
E16	0.00015768	2.3588E-08	0.0115344	1.725E-06
E17	0.00040837	6.5623E-08	0.0378668	6.085E-06
E18	***3.5444E-04***	2.3917E-07	0.0135896	2.199E-06
E19	1.8517E-05	3.1052E-09	0.0096958	1.626E-06
E20	2.7361E-06	4.6005E-10	0.0250781	4.217E-06
E21	3.5316E-08	3.5316E-08	0.0530841	8.539E-06
E22	7.0243E-10	***6.4912E-08***	0.0060656	1.032E-06

5.4 Application of Principal Component Analysis

Following the procedure as presented in Chapter 3: Data Collection, Processing & Evaluation Methodology (p3.8). Number of factors associated with non trivial eigenvalues: 4

5.4.1 Bartlett's Sphericity Test

The Bartlett's sphericity test reveals the following results in *Table 5.6: Bartlett's Sphericity Test for Reliability Data.*

Table 5.6: Bartlett's Sphericity Test for Reliability Data.

Chi-square (observed value)	44.550
Chi-square (critical value) (df = 6)	12.592
One-tailed p-value	< 0.0001
Alpha	0.050

The null hypothesis is rejected because the observed value is 44.550 and the critical value is only 12.592.

Means and standard deviations of the variables are represented in *Table 5.7: Means and Standards for Reliability Data.*

Table 5.7: Means and Standards for Reliability Data.

	Mean	**Standard deviation**
R_1	0.000	0.000
R_2	0.000	0.000
R_3	0.027	0.018
R_4	0.000	0.000

Correlation matrix is represented in *Table 5.8: Correlation Matrix.* The significant values (except diagonal) are in bold and at the level of significance alpha=0.050 (two-tailed test).

Table 5.8: Correlation Matrix.

	R_1	R_2	R_3	R_4
R_1	1	**0.688**	0.419	0.383
R_2	**0.688**	1	0.174	0.172
R_3	0.419	0.174	1	**0.897**
R_4	0.383	0.172	**0.897**	1

The first result to look at is the correlation matrix. There are no negatively correlated values (r = -1). There is a strong correlation with R_2 (system minutes/total MWh) and R_4 (number of interruptions/total MWh).

5.4.2 Eigenvalues of a matrix :

The first eigenvalue equals 2.391 and represents 59.779% of the total variability. The results have produced 4 eigenvalues. The results of these values and their associated percentage variance and percentage cumulative values are tabulated in *Table 5.9: Eigenvalues for Reliability.*

The first two factors allow us to represent 90.554% of the initial variability of the data. This is a good result, but caution must be when interpreting the maps as some information might be hidden in the next factors.

Table 5.9: Eigenvalues for Reliability.

	R_1	R_2	R_3	R_4
Eigenvalue	2.391	1.231	0.277	0.101
% variance	59.779	30.775	6.925	2.522
% cumulative	59.779	90.554	97.478	100.000

5.4.3 Eigenvectors of a matrix

The results are represented in *Table 5.10: Eigenvector Values for Reliability.*

Table 5.10: Eigenvector Values for Reliability.

	R_1	R_2	R_3	R_4
R_1	0.505	0.439	0.738	-0.082
R_2	0.386	0.655	-0.648	0.056
R_3	0.550	-0.427	-0.042	0.716
R_4	0.542	-0.442	-0.185	-0.691

5.4.4 Correlation circle

The first correlation circle is illustrated in *Figure 5.12: Correlation Circle for F1 and F2.*

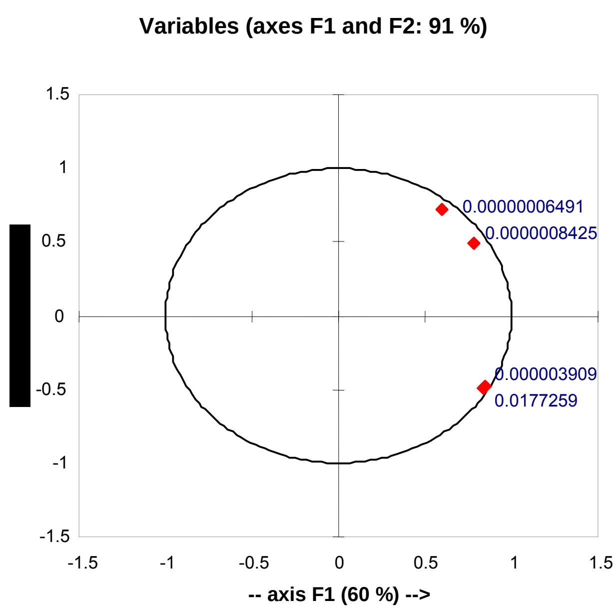


Figure 5.12: Correlation Circle for F1 and F2.

In the above the horizontal axis F1 is linked to R_1 (System minutes/maximum demand), and the vertical axis R_2 (System minutes/total MWh). Reviewing *Table 5.11: Squared Cosines of the Variable Reliability*, we can see that reliability would be best viewed on a F1/F2 map (see encircled values).

Table 5.11: Squared Cosines of the Variable Reliability

	F1	F2	F3	F4
R_1	0.611	0.238	0.151	0.001
R_2	0.356	0.527	0.116	0.000
R_3	0.723	0.225	0.000	0.052
R_4	0.702	0.241	0.009	0.048

The observations relative to these factors are illustrated in *Figure 5.13: Reliability Observations.* The residual vector can be assumed to be negligible due to the masking of the outliers from the original data.

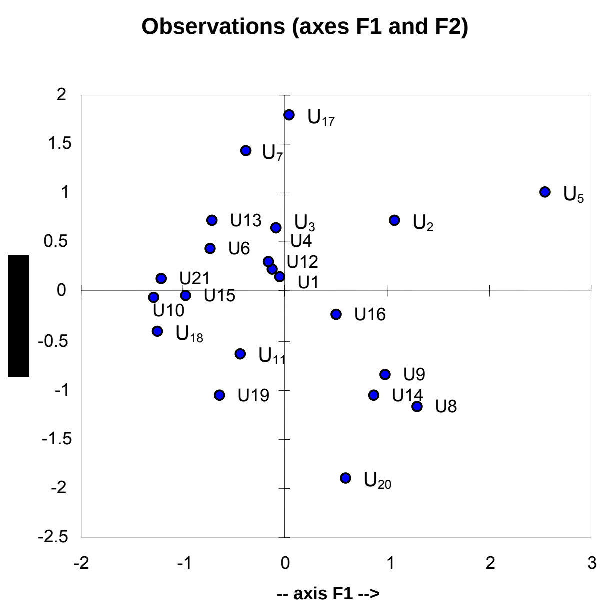


Figure 5.13: Reliability Observations.

5.5 Determining the number of principal components.

The following is a plot of the magnitude of components λ_i versus its number (i). Plotting scree plot from the data obtained from *Table 5.9: Eigen Values for Reliability,* presents the scree plot as illustrated in *Figure 5.14: Reliability Scree Plot.* The elbow occurs in the plot at i = 3. That is, the eigenvalues after λ_2 are all relatively small and approximately the same size. The conclusion can be drawn that only two principal components effectively summarise the total sample size.

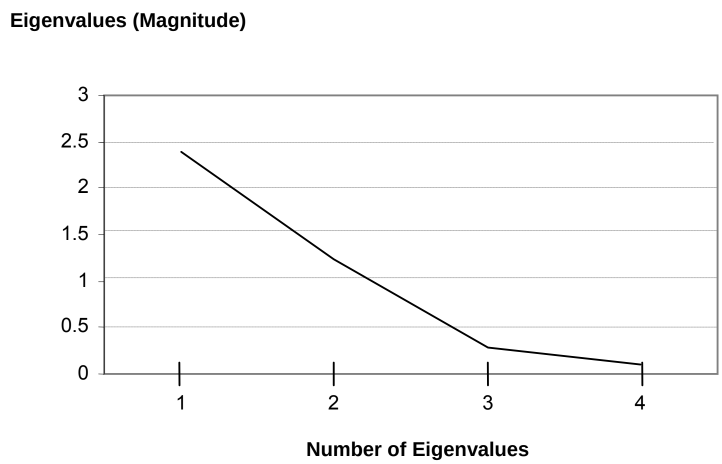


Figure 5.14: Reliability Scree Plot.

5.6 Remaining principal component findings.

The following are the remaining principal component values which have been documented as factor loadings, contributions of the variables, factor scores, Squared cosines of the observations and Contributions of the observations (%).

Table 5.12: Factor Loadings.

	F1	F2	F3	F4
R_1	0.782	0.488	0.388	-0.026
R_2	0.597	0.726	-0.341	0.018
R_3	0.850	-0.474	-0.022	0.228
R_4	0.838	-0.491	-0.097	-0.219

Table 5.13: Contributions of the Variables (%).

	F1	F2	F3	F4
R_1	25.543	19.307	54.472	0.679
R_2	14.890	42.847	41.944	0.318
R_3	30.228	18.273	0.177	51.322
R_4	29.339	19.573	3.407	47.681

Table 5.14: Factor Scores.

Utilities	F1	F2	F3	F4
U_1	-0.051	0.119	0.205	-0.018
U_2	1.896	0.770	0.289	-0.020
U_3	-0.050	0.713	0.434	-0.022
U_4	-0.170	0.212	0.232	-0.013
U_5	4.230	1.082	0.490	0.155
U_6	-1.094	0.462	0.341	-0.071
U_7	-0.316	1.609	0.610	-0.139
U_8	1.814	-1.401	-0.218	0.220
U_9	2.139	-1.680	-0.424	-1.122
U_{10}	-2.050	-0.090	0.155	-0.103
U_{11}	-0.864	-0.748	0.033	0.075
U_{12}	-0.091	0.264	0.033	-0.182
U_{13}	-0.996	0.802	0.375	-0.113
U_{14}	0.811	-1.037	0.279	0.717
U_{15}	-1.588	-0.067	0.234	-0.018
U_{16}	0.680	-0.305	0.187	0.144
U_{17}	0.444	2.716	-1.742	0.127
U_{18}	-2.081	-0.496	0.076	-0.048
U_{19}	-1.264	-1.244	-0.111	0.064
U_{20}	0.492	-2.043	-0.817	0.376
U_{21}	-1.890	0.363	-0.662	-0.008

Table 5.15: Squared Cosines of the Observations.

Utilities	F1	F2	F3	F4
U_1	0.043	0.239	0.712	0.006
U_2	0.842	0.139	0.020	0.000
U_3	0.004	0.726	0.270	0.001
U_4	0.226	0.351	0.421	0.001
U_5	0.926	0.061	0.012	0.001
U_6	0.782	0.139	0.076	0.003
U_7	0.032	0.841	0.121	0.006
U_8	0.615	0.367	0.009	0.009
U_9	0.518	0.319	0.020	0.143
U_{10}	0.990	0.002	0.006	0.003
U_{11}	0.568	0.426	0.001	0.004
U_{12}	0.074	0.621	0.010	0.295
U_{13}	0.555	0.360	0.079	0.007
U_{14}	0.283	0.463	0.033	0.221
U_{15}	0.977	0.002	0.021	0.000
U_{16}	0.757	0.152	0.057	0.034
U_{17}	0.019	0.694	0.285	0.002
U_{18}	0.945	0.054	0.001	0.000
U_{19}	0.505	0.490	0.004	0.001
U_{20}	0.046	0.799	0.128	0.027
U_{21}	0.862	0.032	0.106	0.000

Table 5.16: Contributions of the Observations (%).

Utilities	F1	F2	F3	F4
U_1	0.005	0.055	0.725	0.016
U_2	7.158	2.293	1.438	0.019
U_3	0.005	1.965	3.242	0.023
U_4	0.058	0.174	0.928	0.008
U_5	35.631	4.528	4.135	1.134
U_6	2.385	0.824	1.996	0.239
U_7	0.199	10.015	6.399	0.907
U_8	6.554	7.588	0.819	2.280
U_9	9.108	10.915	3.092	59.472
U_{10}	8.368	0.032	0.411	0.505
U_{11}	1.485	2.164	0.019	0.269
U_{12}	0.017	0.269	0.019	1.562
U_{13}	1.977	2.490	2.418	0.599
U_{14}	1.310	4.161	1.335	24.238
U_{15}	5.023	0.018	0.940	0.016
U_{16}	0.921	0.359	0.602	0.981
U_{17}	0.393	28.546	52.157	0.761
U_{18}	8.627	0.951	0.098	0.108
U_{19}	3.183	5.991	0.210	0.192
U_{20}	0.481	16.153	11.475	6.669
U_{21}	7.110	0.510	7.540	0.003

5.5 Application of Factor Analysis

5.5.1 Results

There were no missing values and again the Pearson correlation coefficient was applied. There were 51 performed iterations with a convergence of 0.001.

The means and standard deviations of the variables are tabulated in *Table 5.17: Means and Standard Deviations for Reliability.*

Table 5.17: Means and Standard Deviations for Reliability.

	Mean	**SD**
R_1	8.43E-07	0.000
R_2	6.49E-08	0.000
R_3	0.017726	0.027
R_4	3.91E-06	0.000

The correlation matrix is represented in *Table 5.18: The Reliability Correlation Matrix.* The significant values are represented in bold at the level of significance alpha=0.050. The results indicate a high correlation with R_2 (system minutes/total MWh) and R_4 (number of interruptions/total MWh). This proves the same result as in the principal component studies.

Table 5.18: The Reliability Correlation Matrix.

	R_1	R_2	R_3	R_4
R_1	1	**0.688**	0.419	0.383
R_2	**0.688**	1	0.174	0.172
R_3	0.419	0.174	1	**0.897**
R_4	0.383	0.172	**0.897**	1

The following table shows the eigenvalues resulting from the factor analysis. It can be seen that from *Table 5.19: Eigenvalues for the Reliability Factor*, that the single-factor solution retains 55.781% of the variability of the initial data.

Table 5.19: Eigenvalues for the Reliability Factor.

	F1	F2
Eigenvalue	2.231	1.003
total % variance	55.781	25.074
% cumulative	55.781	80.855
common % variance	68.989	31.011
% cumulative	68.989	100.000

Table 5.20. Eigenvectors for the Reliability Factor.

	F1	F2
R_1	0.473	0.516
R_2	0.336	0.644
R_3	0.599	-0.419
R_4	0.552	-0.379

Table 5.21: Factor Loadings for the Reliability Factor.

	F1	F2	Initial Communality	Final Communality	Specific Variance
R_1	0.707	0.516	0.565	0.766	0.234
R_2	0.501	0.645	0.489	0.668	0.332
R_3	0.895	-0.420	0.814	0.976	0.024
R_4	0.825	-0.379	0.805	0.825	0.175

Table 5.22: Reproduced Correlation Matrix.

	R_1	R_2	R_3	R_4
R_1	**0.766**	**0.688**	0.415	0.387
R_2	**0.688**	**0.668**	0.178	0.169
R_3	0.415	0.178	**0.977**	**0.897**
R_4	0.387	0.169	**0.897**	**0.824**

Table 5.23: Residual Correlation Matrix.

	R_1	R_2	R_3	R_4
R_1	0.234	0.000	0.003	-0.004
R_2	0.000	0.332	-0.003	0.004
R_3	0.003	-0.003	0.023	0.000
R_4	-0.004	0.004	0.000	0.176

Table 5.24: Estimated Factor Scores.

Utilities	F1	F2
U_1	-0.043	0.137
U_2	1.085	0.726
U_3	-0.090	0.649
U_4	-0.121	0.210
U_5	2.552	1.002
U_6	-0.725	0.424
U_7	-0.371	1.432
U_8	1.306	-1.187
U_9	0.983	-0.849
U_{10}	-1.276	-0.060
U_{11}	-0.429	-0.644
U_{12}	-0.150	0.291
U_{13}	-0.711	0.720
U_{14}	0.877	-1.058
U_{15}	-0.961	-0.051
U_{16}	0.502	-0.250
U_{17}	0.045	1.791
U_{18}	-1.240	-0.420
U_{19}	-0.638	-1.069
U_{20}	0.605	-1.911
U_{21}	-1.199	0.114
U_{22}	-0.043	0.137

5.6 Summary

The comparative results between both principal component analysis and factor analysis are similar *Table 5.25: Summary of Statistical Methods – PCA and FA.* The specific variance was not applicable to principal component analysis. Results from the factor analysis are to be applied in *Chapter 7: Discussion Emanating from the Research* for the derivation of the composite utilisation index.

Table 5.25: Summary of Statistical Methods – PCA and FA.

	Principal Component Analysis		**Factor Analysis**	
Variables	**Factor Loadings (F_1)**	**Specific Variances**	**Factor Loadings (F_1)**	**Specific Variances**
R_1	0.782	-	0.707	0.234
R_2	0.597	-	0.501	0.332
R_3	0.850	-	0.895	0.024
R_4	0.838	-	0.825	0.175

The reliability performance measure component concluded from this study is summarised in the following linear equation format:

$$\textbf{Reliability Component } (R) = 0.707\,R_1 + 0.501\,R_2 + 0.895\,R_3 + 0.825\,R_4 \quad \ldots\ 5.1$$

The above will be brought into context within the Utilisation and Exogenous performance measure components.

Chapter 6

PRIMARY VARIABLE "EXOGENOUS" UNDER DISCUSSION

<u>*Chapter Objective*</u>

The chapter's objective is to provide an in depth discussion of the "exogenous" primary variable (E_f) and its three secondary variables (E_1, E_2, E_3). Input data is screened for outliers. Thereafter factor analysis and principal component analysis are applied to formulate the final equation for E_f. The application of these findings is discussed in detail in Chapter 7: Discussion Emanating from the Research.

6.1 Overview

Once again revisiting John Elkington, we discuss the exogenous variable within the scope of this research. The generation of electricity from primary energy sources impacts either directly, or indirectly, on the social and environmental factors of the international world. The objective of this chapter is to discuss the main influencing factors, and translate them into performance measures for the *exogenous* variable (the third dimension of the transmission network utilisation index). World population and economic growth remain the key drivers for energy developments in the next decades. The relationship between energy consumption, economic growth and the impact on the environment is at this stage well established in research literature, yet the direction of causation of this relationship remains controversial within developing countries. The link between population, GDP and energy has weakened in the last quarter of a century in industrialized countries. Whereas, in the developing countries, given the low initial level of per capita energy consumption, the increase in population and income creates a strong potential for energy consumption growth [6.1 p117] Criqui,P., World Energy Projections to 2030, Int. J. Global Energy Issues, Vol. 1, Nos. 1-4, 2000.

The subject of energy consumption, environmental and economic factors and their relationship to each other has been, and is currently being, extensively researched. No subject documentation within this chapter can do credit to the studies which have been undertaken. The researcher has, however, endeavoured to select specific research material to provide a broad overview on the justification for introducing exogenous factors within the overall transmission network utilisation index. *Exogenous* performance indices are chosen and the raw data filtered to eliminate outliers. The statistical process was followed as described in *Chapter 3: Data Collection, Processing & Evaluation Methodology (p3.8).* The findings are compared from both the principal component analysis and the factor analysis statistical process. The final linear equation for the primary variable *exogenous* is derived from the eigenvalues and factor loadings.

6.2 Primary Energy Consumption Considerations

Direct reference to extracts of the Consumption Report #: DOE/EIA-0484(2003) Released May 1, 2003) provides a setting for the current and future world energy status**.** The forecast presented in the *International Energy Outlook 2003* (*IEO2003*) indicates continuing strong growth for worldwide energy demand over the next 24 years. "The global economy faltered at the end of 2002, and the United States managed a meagre 1-percent annualized growth in the fourth quarter. U.S. stock markets felt the impact of a crisis of consumer confidence following several large corporate scandals in 2002. The weak performance of the U.S. economy in 2002 was felt in world markets as well. The United States is the world's largest economy, and many developing nations are largely dependent on exports to the United States to support their own economic expansion. Worldwide, economic growth is expected to recover over the short term, and in the *IEO2003* reference case, world gross domestic product (GDP) is projected to expand by an average of 3.1 percent per year over the 2001 to 2025 forecast period.

Continuing unrest in the Middle East, the war in Iraq, and a crippling strike in Venezuela aiming to oust President Hugo Chavez all helped to keep oil prices high through much of the past year and into 2003. The Organization of Petroleum Exporting Countries (OPEC) has managed markets to keep the basket oil price above $22 per barrel (nominal) since March 8, 2002.

High world oil prices have the potential to further dampen economic expansion. The weakness of U.S. consumer demand—which has supported economic growth for some time—is matched by likely economic declines in Japan and stagnation in the European Union (EU). Another below-trend performance is expected for the world economy in 2003 before recovery in 2004. Total world energy consumption is expected to expand by 58 percent between 2001 and 2025, from 404 quadrillion British thermal units (Btu) in 2001 to 640 quadrillion Btu in 2025.

The U.S. economy has suffered a number of setbacks in the past 3 years, including the terrorist attacks of September 2001, the significant loss of stock market wealth since 2000, and recent corporate accounting scandals, including U.S. energy company Enron and telecommunications company WorldCom Group. Yet the recession of 2001 was one of the mildest on record, with recovery proceeding slowly in 2002. The recovery— attributed to continuing consumer spending, a strong housing market, and activist fiscal and monetary policies—has been slowed by falling consumer confidence, high oil prices, and war jitters. Debates over another government fiscal stimulus have just begun, but the eventual outcome may well provide a significant boost to the U.S. economy in 2003. U.S. GDP is projected to grow at an average annual rate of 3.0 percent per year from 2001 to 2025.

Canada's economy continued to outperform expectations in 2002. GDP growth in Canada exceeded that of the United States between 1999 and 2002, and in 2002 Canada recorded the strongest growth among the G-8 nations."

A common manner to compare the energy consumption for different geographical regions is to measure the energy consumption per capita. This measurement is however affected by a number of factors. These factors include the following: Climatic variations which include severe climates which tend to use more energy for heating, cooling or refrigeration. Energy intensities of industries such as metal processing plants inflate the energy consumption per capita. Geographical size and distances to travel also affect the energy consumption. In addition, efficiencies in the use of energy and the economic development affect the energy consumption per capita.

Coal use worldwide is projected to increase by 2.2 billion short tons (at a rate of 1.5 percent per year) between 2001 and 2025. Substantial declines in coal use are projected for Western Europe and the EE/FSU countries, where natural gas is increasingly being used to fuel new growth in electric power generation and for other uses in the industrial and building sectors. In the developing world, however, even larger increases in coal use are expected. The largest increases are projected for China and India, where coal supplies are plentiful. Together these two countries account for 86 percent of the projected rise in coal use in the developing world over the forecast period.

Reviewing the primary energy consumption per capita will provide an indication of the expected severity on the environment. The initial assumption would be that the higher the primary energy consumption, the higher will be the impact on the contribution to environmental air pollution. *Figure 6.1 Primary Energy Consumption Per Capita* provides an illustrative view of the main primary energy consumption per capita in tons oil equivalent.

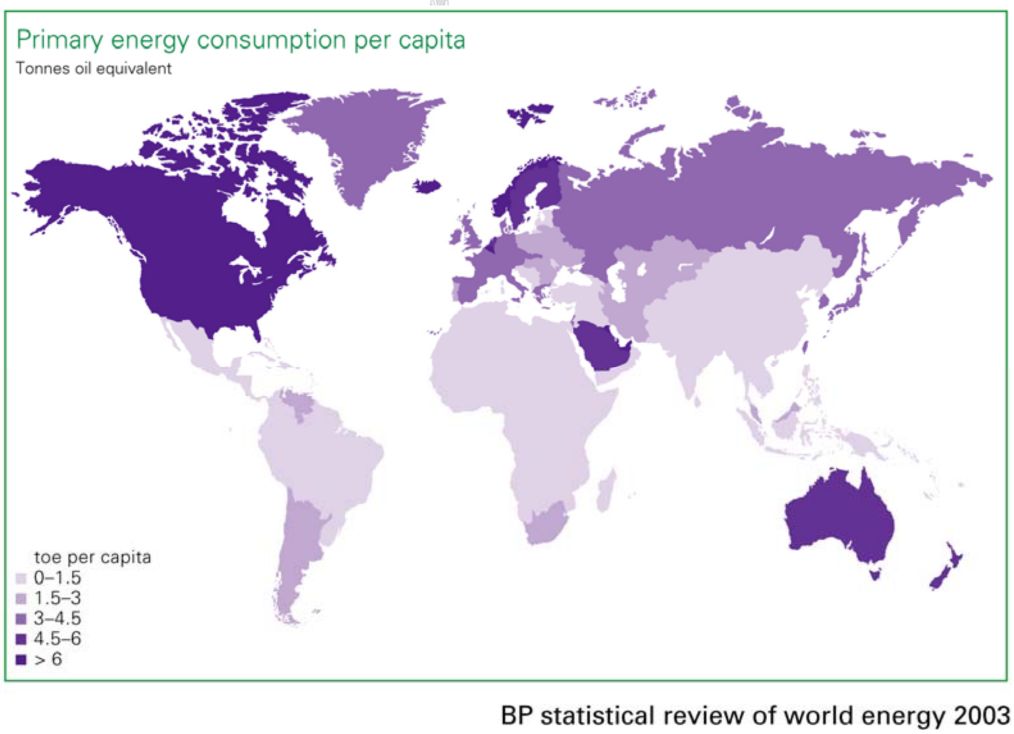
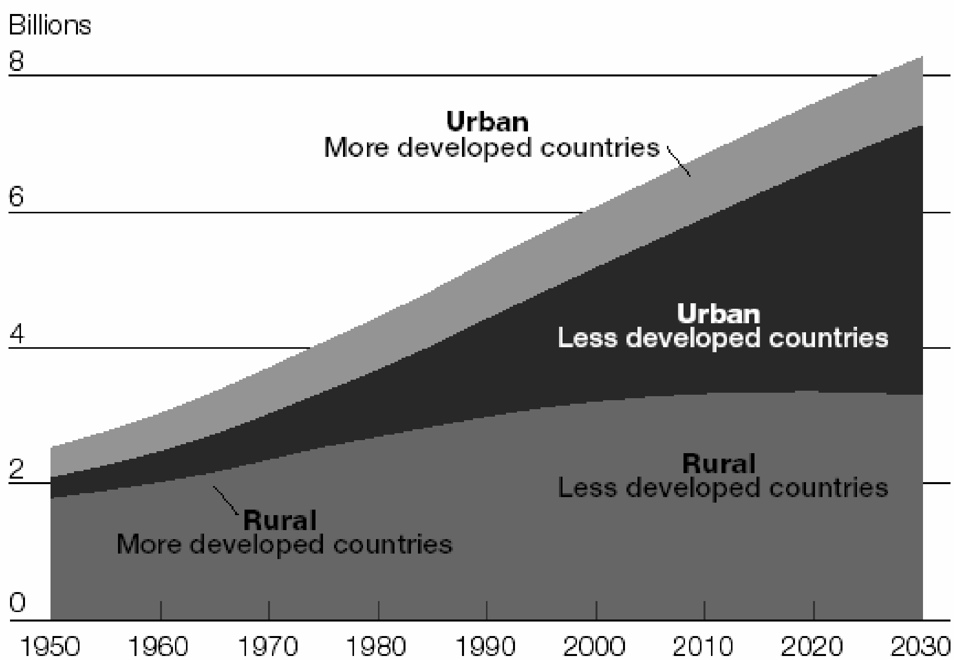


Figure 6.1: Primary Energy Consumption Per Capita.

As can be expected, Northern America and Northern Europe stand out as the highest energy consumers per capita. Relative to the world, the US have significantly higher levels of energy consumption per capita. Other developed countries such as Germany, England and Japan consume less than half the energy as the US. More than half the world's population lives in rural areas of which nearly 90% of them (some 2.8 billion) are in developing countries. The vast majority of these people are dependent on traditional fuels of wood, dung and crop residue. The conversion to energy is often by using primitive and inefficient technologies. This barely allows fulfillment of basic human needs of nutrition, warmth and light. Harnessing energy for productive uses would begin to launch an escape from poverty. In addition the demographic trends worsen the situation because urban populations are projected to grow more rapidly. Approximately 7% of the world's electricity production today could cover the world's basic human needs. Despite advanced technological and management skills, authorities have failed in achieving this relatively modest humanitarian challenge. *Figure 6.2: Growth of Urban and Rural Populations, 1950-2030.*



Source: United Nations, *World Urbanization Prospects: The 2001 Revision* (2002): tables A.3 and A.4.

Figure 6.2: Growth of Urban and Rural Populations, 1950-2030.

Most of the traditional energy use occurs outside the commercial sector, and data on it is geographically scarce and discontinuous. The lack of rural energy use in developing countries confirms its neglect and dampens the development of effective world energy policies. In addition, the vast variety of energy use patterns within short distances makes statistical extrapolation suspicious. Gradually, a transition to modern energy systems (which may utilise traditional energy sources) must be achieved if sustainable economic activity is to be realised in rural areas. Investments in the energy sectors of developing countries have targeted the modern energy sector. A typical project is the Manantali Hydro Power scheme in Mali (Western Africa) which supplies essential electricity to Senegal and Mauritania via a 215kV transmission network.

It is difficult to ascertain in detail the causal relationship between energy consumption and economic activity in most developing countries. Studies undertaken in Pakistan infer that economic growth leads to the growth in petroleum consumption, while in the case of the gas sector, neither economic growth nor gas consumption effect each other. Furthermore, in the power sector it has been found that electricity consumption leads to economic growth without meaningful feedback [6.7] Aqeel, A & Butt, M.S., The Relationship Between Energy Consumption And Economic Growth In Pakistan, Asia-Pacific Development Journal, Vol.8, No.2, December 2001.

Most developing countries have rural electrification programmes with the promotion of renewable energy sources. Despite the number of rural households with access to electricity doubling in the 1970-1990 period, this barely kept pace with population increase. *Table 6.1 Top 100 Traditional Fuel Consumption as a % of Total Energy Use* illustrates the high percentage of traditional fuel consumption in developing countries. Traditional fuel consumption is ranked as the top 100 countries.

Table 6.4 Top 100 Traditional Fuel Consumption as a % of Total Energy Use.

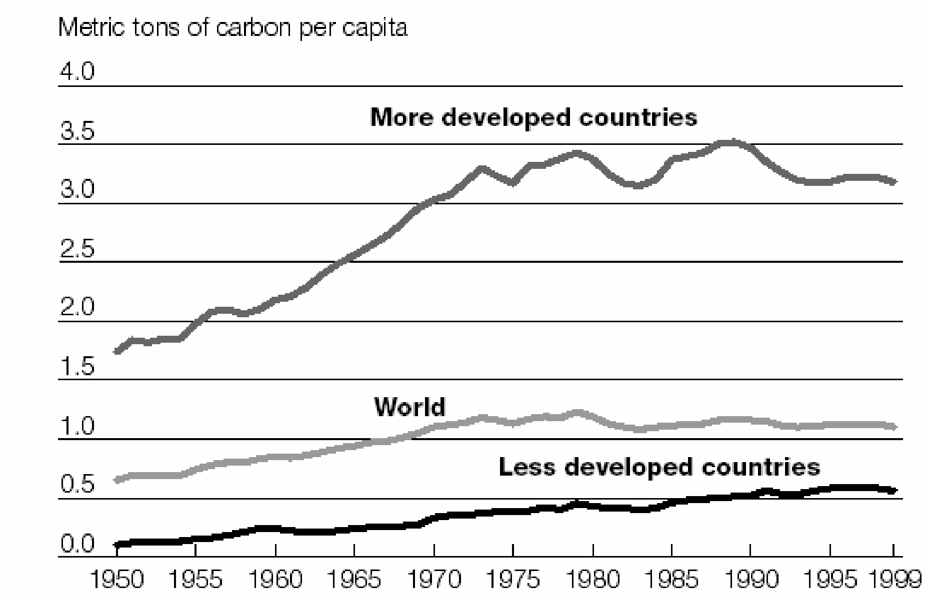
	Country	Description	Graphical Illustration
1	Chad	97.6%	
2	Eritrea	96.0%	
3	Ethiopia	95.9%	
4	Burundi	94.2%	
5	Congo, Democratic Republic of the	91.7%	
6	Cote d'Ivoire	91.5%	
7	Mozambique	91.4%	
8	Tanzania	91.4%	
9	Uganda	89.7%	
10	Nepal	89.6%	
	⋮	⋮	
87	United States	3.8%	
88	United Kingdom	3.3%	
	⋮	⋮	
90	Croatia	3.2%	
91	Turkey	3.1%	
92	Lebanon	2.5%	
93	Korea, South	2.4%	
94	Belgium	1.6%	
95	Czech Republic	1.6%	
96	Hungary	1.6%	
97	Japan	1.6%	
98	Algeria	1.5%	
99	Slovenia	1.5%	
100	Yemen	1.4%	
	Average	**39.42 %**	

Source: MasterNation.com

According to The Coalition for Affordable and Reliable Electricity (CARE), demographic trends are complicating the task of alleviating rural energy poverty. With the two billion ever in mind, we need to look more closely at what this number means, not only now, but more importantly in the near future. When this report went to press in 1999, the world's population had officially passed the 6 billion mark. Population growth projections published by the United Nations indicate that the world's population is expected to grow by 45% from 5.8 billion in 1996 to 8.4 billion in 2030 (UN, 1997). However, these numbers need to be further disaggregated, to understand their implications for rural energy poverty. If we look at where this 45% growth is projected to occur, we find that it is virtually all in the developing countries, with close to 41% being contributed by growth in their urban populations, and only about 4% by growth in their rural populations. While precision is difficult, most energy in rural areas is applied for basic human need.

The relationship between electricity consumption, economic, social and environment are not independent. Electricity accounts for approximately 21% of total energy production and fossil fuels make up 94% of the world's energy mix. 2600 cubic kilometers of fresh water are consumed annually for irrigation. Fresh water use has risen by two thirds to 4200 cubic kilometers a year when one fifth of the world's population lack access to safe drinking water, and one tenth for proper sanitation. Despite the possibility of being able to provide electricity from clean energy sources such as hydro electricity, one must acknowledge that the end consumer generally has possibly the largest environmental impact on air pollution contributed by large processing and industrialised plants. Consider *Figure 6.2: Per Capita Carbon Dioxide (CO2) Emissions, 1950–1999*. The more developed countries produce almost 3.5 metric tons of carbon per capita. Thermal or coal fired generating units have recently, and are still continuing, to improve the carbon omissions. Their total contribution to the overall environmental air pollution is reducing. *Table 6.2: OECD Electricity Supply* represents the energy distribution which provides an indication of the major pollution contributors. On the other hand, economists at Pennsylvania State University have concluded that the use of abundant U.S. coal reserves to generate electricity creates economic empowerment for millions of American businesses and working families.

World carbon dioxide emissions are expected to increase by 3.8 billion metric tons carbon equivalent over current levels by 2025—growing by 1.9 percent per year—if world energy consumption reaches the levels projected in the *IEO2003* reference case. According to this projection, world carbon dioxide emissions in 2025 would exceed 1990 levels by 76 percent. Oil and natural gas contribute about 1.5 and 1.3 billion metric tons, respectively, to the projected increase from 2001, and coal provides the remaining 1.1 billion metric tons carbon equivalent.



Source: Updated and adapted from F.A.B. Meyerson, "Population, Carbon Emissions, and Global Warming: The Forgotten Relationships at Kyoto," *Population and Development Review* 24, no. 1 (1998): 115-30.

Figure 6.3: Per Capita Carbon Dioxide (CO2) Emissions, 1950–1999.

Table 6.2: OECD Electricity Supply

ELECTRICITY SUPPLY [1]

OECD [7] Supply *TWh*

	2001	2002	3Q2001	4Q2001	1Q2002	2Q2002	3Q2002	4Q2002	Dec-Feb 2003	Jan-Feb 2003	Feb 2003
+Combustible Fuels	5573.5	5607.7	1476.5	1369.9	1373.7	1302.0	1497.3	1434.6	1476.9	977.9	463.2
+Nuclear	2206.6	2228.2	551.3	568.1	571.5	540.3	560.2	556.2	582.1	382.1	179.0
+Hydro	1265.7	1285.5	293.3	297.4	318.6	338.3	309.8	318.8	347.3	231.9	109.6
+Geothermal/Other	111.3	118.6	28.2	28.4	31.4	28.5	29.8	28.9	31.1	20.9	10.4
=Indigenous Production	**9157.1**	**9240.0**	**2349.2**	**2263.9**	**2295.2**	**2209.2**	**2397.1**	**2338.5**	**2437.3**	**1612.8**	**762.2**
+Imports	333.8	351.7	79.2	88.7	91.6	84.3	86.6	89.2	92.8	61.1	29.7
-Exports	324.9	340.6	80.2	85.3	86.8	83.5	85.3	84.9	89.7	59.4	28.2
= Consumption (Observed)	**9166.0**	**9251.1**	**2348.3**	**2267.3**	**2300.0**	**2210.0**	**2398.3**	**2342.8**	**2440.3**	**1614.4**	**763.7**

Source: International Energy Agency

The study, *Projected Economic Impacts of U.S. Coal Production and Utilisation*, investigated the impact of coal-generated electricity on state economies in the United States. The study found that coal-based electricity, including the production of coal from the ground, creates substantial benefits to the overall U.S. economy. Today, coal provides the fuel for over half of the power consumed in the United States, and the economists concluded that in 2010 coal production and electricity generation would be responsible for:

- $163 to $659 billion in increased economic output;
- $40 to $224 billion in increased household earnings; and
- 800,000 to 6.4 million additional American jobs.

Most of these economic benefits derive from the extraordinary interdependence of the U.S. economy. Because all businesses rely on electricity to produce and sell goods and services, the economic power of the electric utility industry extends far beyond the generation and sale of electricity. Coal-based electricity produces powerful ripple effects that benefit the American economy as a whole.

The study was conducted by Dr. Adam Rose and Bo Yang, economists at Penn State University. They used certain economic assumptions to present their findings. In the first instance, the study assumes varying levels of "linkage" (maximum versus minimum) between the coal-based electricity industry and other sectors of the economy. The linkage variable measures the degree to which coal-based electricity produces ripple effects that benefit other industries and sectors. These data are then refined by taking into account the economic effects of using a higher-cost fuel (in this case, natural gas) as a substitute for low-cost coal. By factoring in these substitution costs, the study shows how coal's economic advantages are even greater when considering the costs of using a more expensive alternative fuel. The year 2010 was selected for modeling because regulatory programs aimed at displacing coal would need to be implemented over time.

Because reliance on coal as a fuel source for generating electricity varies from region to region, the economic benefits are not evenly spread across the nation. The economic advantages for coal-producing states are evident. More surprising, however, are the economic benefits realised by states that do not produce coal, but use it as a primary fuel for electricity generation.

The study concludes that coal-based electricity will result in substantial economic benefits for large and small states alike. For example, Illinois, Indiana, Ohio, Texas and Pennsylvania each stand to gain from $21 billion to $32 billion in increased economic output. Smaller states also share in the advantages, with New Hampshire, Connecticut, Oregon and South Dakota each projected to gain from $560 million to $720 million in expanded output.

"This new analysis proves what we have known for a long time," said Stephen L. Miller, President and CEO of the Center for Energy and Economic Development (CEED). "Electricity from coal provides economic empowerment to local communities, small businesses, and working families".

According to Miller, the study provides an additional level of details relative to the ongoing national energy policy debate. "Despite electricity from coal's low cost and improving environmental performance, some special interest groups still believe we should abandon this abundant domestic energy resource. The Rose/Yang study provides additional empirical proof that coal-based electricity is an essential element of a balanced energy portfolio that increases energy security and provides economic empowerment for American families," said Miller. From the above findings we can confidently assume that the use of electricity as an energy source contributes towards the industrialized countries GDP.

Of interest is that of the 68 countries that use 100% fossil fuel for the generation of electricity, nearly all are in developing countries [master nation.com]. Of further interest is that the 40 of the hydro generators contributing to the percentage of countries is also in developing countries. However, one must realise that in many cases this electricity is mainly generated for the small industrialized economy and the majority of the population is still using traditional fuels.

On reviewing the exogenous performance measures it becomes evident that these measures are dependent on the economic and social classification of a country. Obvious and internationally recognised classification would be “developed” (or industrialised) and “developing” (or emerging) countries. The researcher has concluded that the addition of the developing countries in the exogenous factors would be appropriate for the following reasons. Firstly, accurate data is not available regarding the mix of industrial and domestic energy use. Secondly, there is too large a disparity between the omission of CO2 gases in the case of developed and developing countries. And thirdly, the fact that there has been no participation from the developing countries in the previous *utilisation* and *reliability* variables, invalidates the use thereof.

6.3 Input Data

Stemming from the previous discussion in section *6.2 Primary Energy Considerations*, the researcher has chosen the following input data for the measurement of the *exogenous* indices:

- Per capita energy consumption (million tons / capita) [E_1].
- CO_2 emissions per capita (million tons / capita) [E_2].
- Gross Domestic Product / capita ($\$_{US}$ / capita) [E_3].

Detailed definitions and motivations of these secondary variables were discussed in *Chapter 1: Background* under *section 1.4.4.1: Exogenous secondary variables (E_1, E_2, & E_3).*

The data under investigation is tabulated in *Table 6.4: Raw Data Processed.*

Table 6.4: Raw Data Processed.

Countries	E1	E2	E3
C_1	252.2	5.05	27012
C_2	355.4	5.63	35935
C_3	101.3	2.04	20660
C_4	164.0	2.51	25427
C_5	210.4	2.24	19293
C_6	72.1	1.01	10340
C_7	250.6	2.51	26275
C_8	424.3	2.73	31601
C_9	417.7	5.02	28932
C_{10}	95.2	2.12	9529
C_{11}	251.3	1.77	25617
C_{12}	101.3	1.70	18048
C_{13}	104.7	2.37	9439

On closer observation it becomes clear that the data above varies significantly between the largest and smallest values. As in the previous two chapters a Box Plot was performed to establish data considered as outliers.

Figures 6.4 to 6.6 represents Box Plots of E_1, E_2 and E_3 respectively.

Smallest	*Q1*	*Median*	*Q3*	*Largest*	*IQR*	*Outliers*
72.1	*101.3*	*210.4*	*303.8*	*424.3*	*202.5*	0

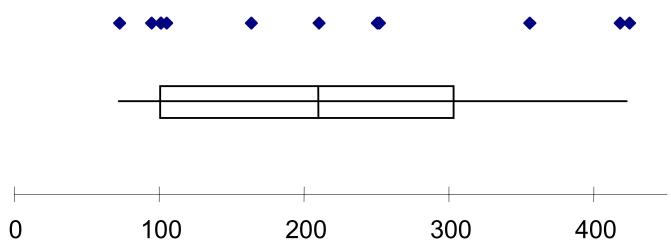


Figure 6.4: Box Plot of E_1.

Smallest	*Q1*	*Median*	*Q3*	*Largest*	*IQR*	*Outliers*
1.01	*1.905*	*2.37*	*3.875*	*5.63*	*1.97*	0

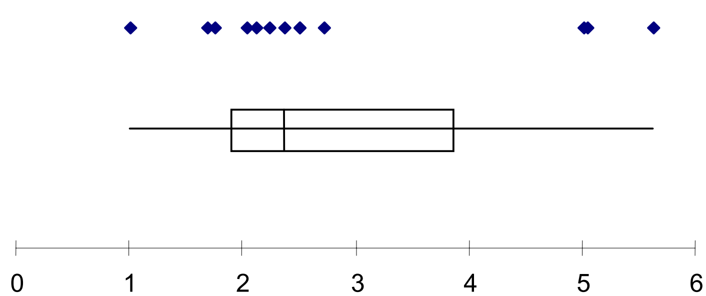


Figure 6.5: Box Plot of E_2.

Smallest	Q1	Median	Q3	Largest	IQR	Outliers
9439	14194	25427	30266.5	35935	16072.5	0

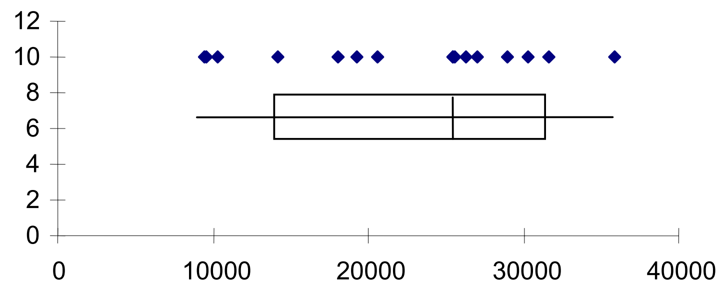


Figure 6.6: Box Plot of E_3.

There were no outliers in either of the above secondary variables.

6.4 Application of Principal Component Analysis

As previously discussed in chapters 4 and 5, the following procedure is presented in *Chapter 3: Data Collection, Processing & Evaluation Methodology (p3.8).*

There were 13 numbers of observations (rows) and 3 variables (columns) with no missing values. A Pearson correlation coefficient was performed without axes rotation. Number of factors associated with non trivial eigenvalues: 3

6.4.1 Bartlett's Sphericity Test

The Bartlett's sphericity test reveals the following results in *Table 6.5: Bartlett's Sphericity Test For Exogenous Data.*

Table 6.5: Bartlett's Sphericity Test for Exogenous Data.

Chi-square (observed value)	20.362
Chi-square (critical value) (df = 6)	7.815
One-tailed p-value	0.000
Alpha	

This is the case above where the observed value is 20.362 and the critical value is only 7.815. Therefore, the null hypothesis is rejected.

Means and standard deviations of the variables are represented in *Table 6.6: Means and Standards for Exogenous Data.*

Table 6.6: Means and Standards for Exogenous Data.

	Mean	**Standard deviation**
E_1	215.423	118.966
E_2	2.823	1.392
E_3	22162.154	8210.214

Correlation matrix is represented in *Table 6.7: Correlation Matrix*. The significant values (except diagonal) are in bold and at the level of significance alpha=0.050 (two-tailed test).

Table 6.7: Correlation Matrix.

	E_1	E_2	E_3
E_1	1	**0.689**	**0.853**
E_2	**0.689**	1	**0.680**
E_3	**0.853**	**0.680**	1

6.4.2 Eigenvalues of a matrix:

The results have produced 3 eigenvalues and are tabulated in *Table 6.8: Eigenvalues for Exogenous (E_f).*

Table 6.8: Eigenvalues for Exogenous (E_f).

	E_1	E_2	E_3
Eigenvalues	2.484	0.369	0.147
% variance	82.798	12.291	4.912
% cumulative	82.798	95.088	100.000

6.4.3 Eigenvectors of a matrix

The results of each eigenvector are represented in *Table 6.9: Eigenvector Values for Exogenous*.

Table 6.9: Eigenvector Values for Exogenous (E_f).

	E_1	E_2	E_3
E_1	0.593	-0.371	0.715
E_2	0.546	0.837	-0.019
E_3	0.591	-0.402	-0.699

6.4.4 Correlation circle

The first correlation circle is illustrated in *Figure 6.7: (below on axes F1 and F2).*

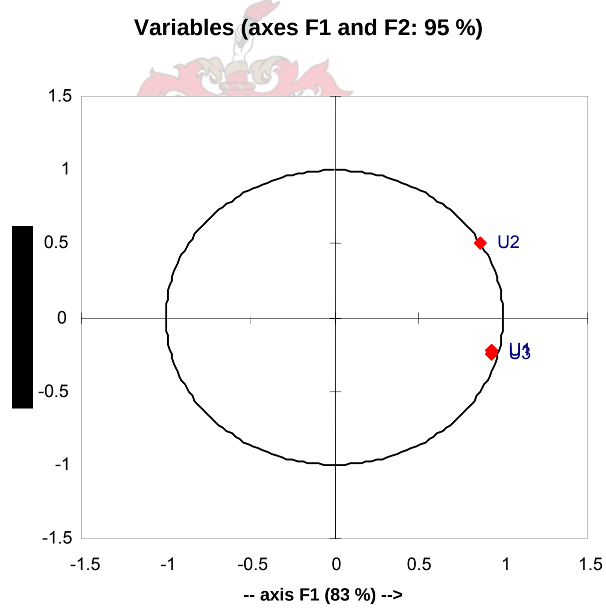


Figure 6.7: Correlation circle for F1 and F2.

Reviewing *Table 6.10: Squared Cosines of the Variable Exogenous,* we can see that exogenous would be best viewed on a F1/F2 map (see encircled values).

Table 6.10: Squared Cosines of the Variable Exogenous

	F1	**F2**	**F3**
E_1	0.874	0.051	0.075
E_2	0.741	0.259	0.000
E_3	0.868	0.060	0.072

The observations relative to these factors are illustrated in *Figure 6.8: Exogenous Observations.*

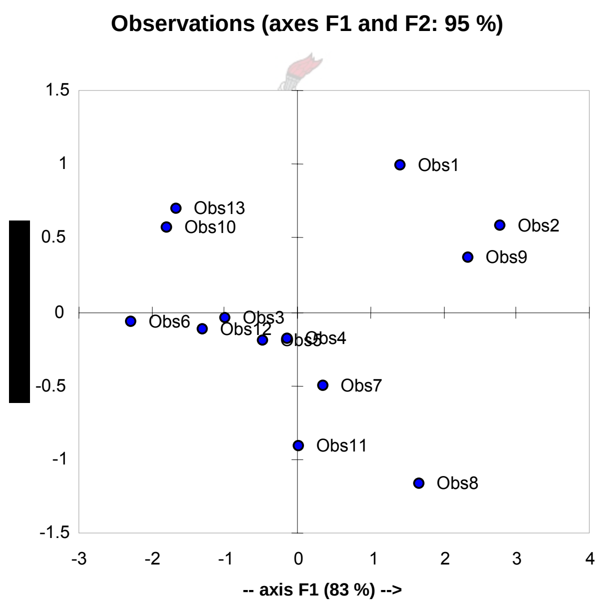


Figure 6.8: Exogenous Observations.

6.5 Determining the number of principal components.

The above simulation has produced 3 principal components (F1, F2, and F3).

The scree plot is plotted from the data obtained from *Table 6.9: Eigenvalues for Exogenous*. The scree plot is illustrated in *Figure 6.9: Exogenous Scree Plot.* The elbow occurs in the plot at i = 3. That is, the eigenvalues after λ_2 are all relatively small and approximately the same size. The conclusion can be drawn that only two principal components effectively summarise the total sample size.

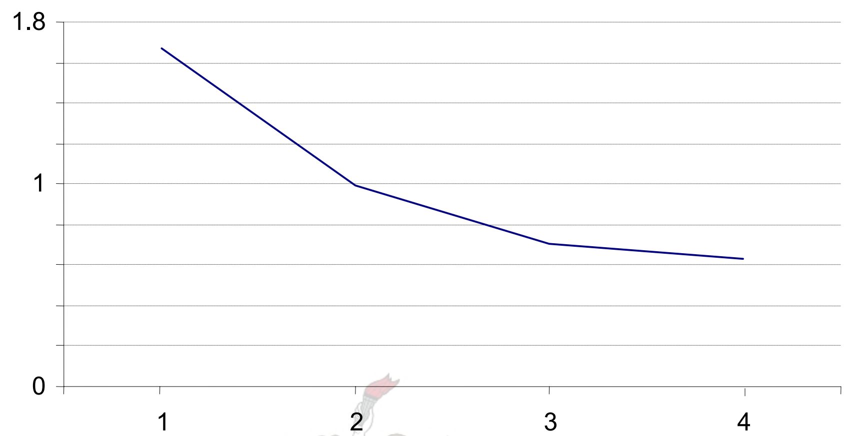


Figure 6.9: Exogenous Scree Plot.

6.6 Remaining principal component findings.

The following are the remaining principal component values which have been documented as factor loadings, contributions of the variables, factor scores, squared cosines of the observations and contributions of the observations (%). These are represented in Tables 6.11 to 6.15.

Table 6.11: Factor loadings.

	F1	F2	F3
E_1	0.935	-0.225	0.274
E_2	0.861	0.508	-0.007
E_3	0.932	-0.244	-0.268

Table 6.12: Contributions of the Variables (%).

	F1	F2	F3
E_1	35.190	13.737	51.073
E_2	29.849	70.114	0.037
E_3	34.961	16.148	48.890

Table 6.13: Factor Scores.

Countries	F1	F2	F3
C_1	1.407	0.988	-0.223
C_2	2.792	0.579	-0.371
C_3	-0.985	-0.042	-0.547
C_4	-0.144	-0.188	-0.583
C_5	-0.461	-0.195	0.222
C_6	-2.278	-0.066	0.171
C_7	0.349	-0.499	-0.135
C_8	1.685	-1.169	0.452
C_9	2.359	0.360	0.608
C_{10}	-1.785	0.570	0.363
C_{11}	0.014	-0.914	-0.064
C_{12}	-1.306	-0.119	-0.320
C_{13}	-1.646	0.695	0.425

Table 6.14: Squared Cosines of the Observations

Countries	F1	F2	F3
C_1	0.659	0.325	0.017
C_2	0.943	0.040	0.017
C_3	0.763	0.001	0.235
C_4	0.053	0.089	0.858
C_5	0.708	0.127	0.165
C_6	0.994	0.001	0.006
C_7	0.313	0.641	0.047
C_8	0.644	0.310	0.046
C_9	0.918	0.021	0.061
C_{10}	0.875	0.089	0.036
C_{11}	0.000	0.995	0.005
C_{12}	0.936	0.008	0.056
C_{13}	0.803	0.143	0.053

Table 6.15: Contributions of the Observations (%)

Countries	F1	F2	F3
C_1	6.129	20.360	2.593
C_2	24.137	6.984	7.181
C_3	3.002	0.037	15.609
C_4	0.064	0.737	17.721
C_5	0.657	0.791	2.578
C_6	16.068	0.090	1.525
C_7	0.377	5.200	0.946
C_8	8.790	28.497	10.675
C_9	17.228	2.708	19.312
C_{10}	9.870	6.775	6.894
C_{11}	0.001	17.446	0.215
C_{12}	5.284	0.294	5.335
C_{13}	8.393	10.080	9.415

6.5 Application of Factor Analysis

6.5.1 Introduction

As previously discussed in chapters 4 and 5, the following procedure is presented in *Chapter 3: Data Collection, Processing & Evaluation Methodology (p3.8).*

6.5.2 Results

XLSTATS-Pro 6.1.9 produced the following Factor Analysis results.

The means and standard deviations of the variables are tabulated in Table *6.16: Means and Standard Deviations for Exogenous*.

Table 6.16: Means and Standard Deviations for Exogenous.

	Mean	**SD**
E_1	215.423	123.824
E_2	2.823	1.449
E_3	22162.154	8545.461

The correlation matrix is represented in *Table 6.17: The Exogenous Correlation Matrix.* There were no significant correlation values at the level of significance alpha = 0.050. This is to be considered in the *Chapter 7: Discussion Emanating from the Research*, and proves the same result as in the principal component studies.

Table 6.17: The Exogenous Correlation Matrix

	E_1	E_2	E_3
E_1	1	**0.689**	**0.853**
E_2	**0.689**	1	**0.680**
E_3	**0.853**	**0.680**	1

The following table shows the eigenvalues resulting from the factor analysis. It can be seen that from *Table 6.18. Eigenvalues for the Exogenous Factor*, that the single-factor solution retains 75.139% of the variability of the initial data.

Table 6.18. Eigenvalues for the Exogenous Factor.

	F1
Eigenvalue	2.254
total % variance	75.139
% cumulative	75.139
common % variance	100.000
% cumulative	100.000

The additional relevant findings are represented in Figures 6.19 to 6.23.

Table 6.19. Eigenvectors for the Exogenous Factor.

	F1
E_1	0.618
E_2	0.494
E_3	0.611

Table 6.20: Factor Loadings for the Exogenous Factor.

	F1	**F2**	**Initial Communality**	**Final Communality**	**Specific Variance**
E_1	0.928	0.749	0.861	0.139	0.928
E_2	0.742	0.506	0.551	0.449	0.742
E_3	0.918	0.743	0.842	0.158	0.918

Table 6.21: Reproduced Correlation Matrix.

Utility	***E_1***	***E_2***	***E_3***	***E_4***
E_1	**0.861**	**0.688**	**0.852**	**0.861**
E_2	**0.688**	0.550	**0.681**	**0.688**
E_3	**0.852**	**0.681**	**0.843**	**0.852**

Table 6.22: Residual Correlation Matrix.

Utility	***E_1***	***E_2***	***E_3***
E_1	0.139	0.000	0.001
E_2	0.000	0.450	-0.001
E_3	0.001	-0.001	0.157

Table 6.23: Estimated Factor Scores.

Countries	**F1**
C_1	0.569
C_2	1.463
C_3	-0.586
C_4	-0.066
C_5	-0.210
C_6	-1.297
C_7	0.315
C_8	1.277
C_9	1.309
C_{10}	-1.154
C_{11}	0.224
C_{12}	-0.744
C_{13}	-1.101

6.6 Summary

The results summarised and illustrated in *Table 6.24: Summary of statistical methods – PCA and FA,* show that for purposes of this study the comparative results between both principal component analysis and factor analysis are similar. When comparing the two, the difference was: E_1 less than 1%, E_2 13.82% and E_3 1.5%. The specific variance was not applicable to principal component analysis. Results from the factor analysis are to be applied in *Chapter 7: Discussion Emanating from the Research* for the derivation of the composite *exogenous* index.

Table 6.24: Summary of statistical methods – PCA and FA.

	Principal Component Analysis		**Factor Analysis**	
Variables	**Factor Loadings (F_1)**	**Specific Variances**	**Factor Loadings (F_1)**	**Specific Variances**
E_1	0.935		0.928	0.928
E_2	0.861		0.742	0.742
E_3	0.932		0.918	0.918

The *Exogenous* performance measurement component concluded from this chapter is summarised in the following linear format:

$$\textbf{\textit{Exogenous} Component } (E_f) = 0.928\, E_1 + 0.742\, E_2 + 0.918\, E_3 \ldots \qquad [6.1]$$

The above will be discussed and brought into context with the Utilisation and Reliability performance measure components and is discussed in *Chapter 7: Discussion Emanating from the Research*.

Chapter 7

DISCUSSION EMANATING FROM THE RESEARCH

Chapter Objective

This chapter's objective is to provide a discussion emanating from the research study. It discusses all primary variables (U_f, R_f and E_f) and the specific secondary variables ($U_{1,\ 2,\ 3\ \&\ 4}$, $R_{1,\ 2,\ 3\ \&\ ,4}$ and $E_{1,\ 2,\ \&\ 3}$ in relation with each primary variable component. Scatter graphs and clustering analysis are used to investigate the relationships.

7.2 Primary Variable "Utilisation"

Following from *Chapter 4: Primary Variable "Utilisation" Under Discussion, Section 4.6 Summary (p4.43).* The final equation derived from the comparison between the principal component analysis and the factor analysis was:

***Utilisation* Component (*U*) = 0.539 U_1 + 0.446 U_2 + 0.653 U_3 + 0.311 U_4** … [7.1]

For simplicity the above factor loading are modified to a total *weighting of 1*. This produces the following linear equation.

***Utilisation* Component (U_f) = 0.277 U_1 + 0.229 U_2 + 0.334 U_3 + 0.160 U_4** … [7.2]

Keeping in mind, the above derivation masks outliers from the original data identified, by the Box Plot process. What is concluded at this stage is the *utilisation* component (Chapter 4) of the overall *transmission network utilisation* measurement index, the above forms one dimension of the three dimensional model. The other dimensions to be concluded are the *reliability* (Chapter 5) and *exogenous* (Chapter 6) dimensions (primary variables). However, the research is not concluded until the following is answered: "How does linear *equation 7.2* relate to the original data obtained in *Chapter 4: Primary Variable "Utilisation" Under Discussion, Table 4.4 Raw Data Processed <u>Without</u> Masking the Outlier* " [p4.24]?

Data without masking the outliers are specifically chosen to determine whether there are outliers that form part of a possible linear relation. *Table 7.1: Utilisation Data Processed <u>Without</u> Outlier Masking* represents the original raw data and the single components of linear equation 7.1, and U_f represents the final summed value of the secondary variables. The bolded italic values represent the original outliers as identified by the Box Plot in *Chapter 4: Primary Variable "Utilisation" Under Discussion, Table 4.5: Summary of Box Plot U Values (p4.25).* Thereafter, each component is separately plotted against the final value (U_f) to determine the relationship – linear or cluster. To facilitate referencing, the secondary variables are repeated below.

- Maximum Demand (MW)/Number of Installed Transformers [U_1].
- Maximum Demand (MW)/Length of Transmission Lines (km) [U_2].
- Energy Losses (MWh)/Total Energy (MWh) [U_3].
- Maximum Demand (MW)/Total Energy Demanded (MWh) [U_4].
- Primary *Utilisation* component (index with no units) [U_f].

Table 7.1: Raw Data Processed <u>Without</u> Outlier Masking.

Utility	***Original Raw Data***				***Components of Equation 7.1***				***U_f***
	U_1	***U_2***	***U_3***	***U_4***	***$0.277U_1$***	***$0.229U_2$***	***$0.334U_3$***	***$0.160U_4$***	
E_1	24.09375	0.4171	0.03016	***0.0002205***	6.6739688	0.0955159	0.0100734	0.00003528	***6.7795934***
E_2	42.298246	0.524	0.0045	0.000174	11.716614	0.119996	0.001503	0.00002784	11.838141
E_3	46.875	0.9199	0.02722	0.0001793	12.984375	0.2106571	0.0090915	0.000028688	13.204152
E_4	20.340996	1.3193	0.02145	0.0001623	5.6344559	0.3021197	0.0071643	0.000025968	5.9437659
E_5	46.732759	0.581	0.05282	0.0001737	12.944974	0.133049	0.0176419	0.000027792	13.095693
E_6	10.693032	0.3522	0.04371	0.0001689	2.9619699	0.0806538	0.0145991	0.000027024	3.0572498
E_7	39.826923	0.9501	0.045	0.0001642	11.032058	0.2175729	0.01503	0.000026272	11.264687
E_8	47.07483	1.0386	0.00017	0.0001689	13.039728	0.2378394	5.678E-05	0.000027024	13.277651
E_9	206.16667	1.0407	0.03871	0.0001712	57.108168	0.2383203	0.0129291	0.000027392	57.359444
E_{10}	***279.11429***	1.3125	0.045	***0.0003095***	77.314658	0.3005625	0.01503	0.00004952	*77.6303*
E_{11}	67.240506	0.8836	0.03022	0.0001855	18.62562	0.2023444	0.0100935	0.00002968	18.838088
E_{12}	136.82716	0.9683	0.01094	0.0001617	37.901123	0.2217407	0.003654	0.000025872	38.126544
E_{13}	14.96875	1.457	0.04861	***0.0002114***	4.1463438	0.333653	0.0162357	0.000033824	***4.4962663***
E_{14}	34.319742	1.6694	0.0472	***0.0001744***	9.5065685	0.3822926	0.0157648	0.000027904	***9.9046538***
E_{15}	14.365093	0.6758	0.047	0.0001157	3.9791308	0.1547582	0.015698	0.000018512	4.1496055
E_{16}	120.04196	1.977	0.01481	0.0001496	33.251623	0.452733	0.0049465	0.000023936	33.709326
E_{17}	30.637954	0.7808	0.03371	0.0001607	8.4867133	0.1788032	0.0112591	0.000025712	8.6768013
E_{18}	147.17089	1.8414	0.01209	0.0001618	40.766337	0.4216806	0.0040381	0.000025888	41.192081
E_{19}	***896.50***	1.5312	0.01703	0.0001677	248.3305	0.3506448	0.005688	0.000026832	*248.68686*
E_{20}	119.62613	1.4613	0.01424	0.0001681	33.136438	0.3346377	0.0047562	0.000026896	33.475859
E_{21}	63.534722	1.0373	0.02776	0.0001609	17.599118	0.2375417	0.0092718	0.000025744	17.845957
E_{22}	63.309305	***3.3595***	0.01847	0.0001702	17.536677	0.7693255	0.006169	0.000027232	***18.312199***

This first scatter plot is represented in *Figure 7.1: Scatter Plot for U_f and U_1.* The following can be interpreted from the scatter plot. There is a definite linear relationship between the derived linear equation's final value *(U_f)* and the Maximum Demand (MW)/Number of Installed Transformers (U_1). This is somewhat surprising due to the following: The researcher would have expected a linear relationship to have the installed transformer capacity and *not* the number of transformers to be used. It can be reasonably assumed that installed transformer capacity would be more representative of the maximum demand than the number of transformers. Unfortunately this data was not available to confirm this assumption. However, the research indicates that the number of transformers proved a reliable measure and does relate to the maximum demand. Of interest is the previously identified outliers (circled) - 279.11429 and 896.50 - are not outliers at all. They are included on the top scale of the linear relationship – a lesson to be remembered when excluding outliers! How does this assist with benchmarking? A reasonable approach would be to position a utility along the linear relationship (solid grey coloured line). An allowable deviation could be ascertained by management strategic objectives within a predetermined range – between A and A'. See section 7.6.1 to 7.6.3 for more detail relating to this application.

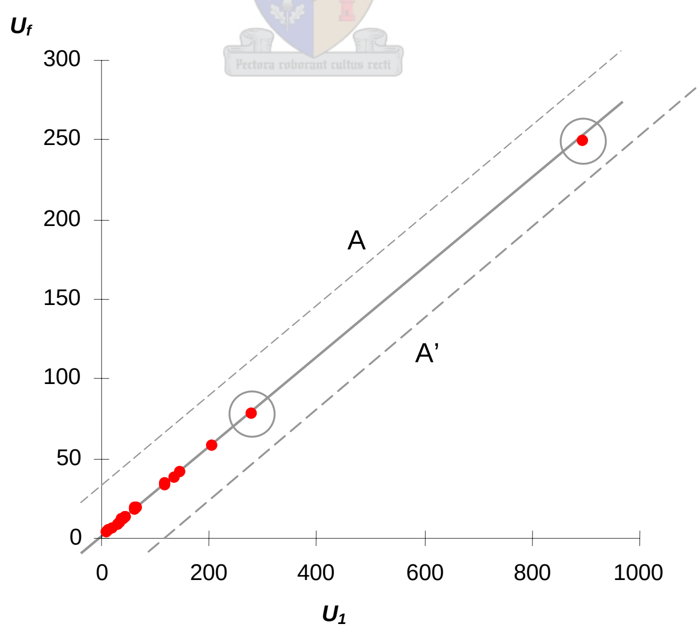


Figure 7.1: Scatter Plot for U_f and U_1.

Scatter plots in Figures 7.1.2 to 7.1.3 represent a different outcome. The relationship between U_f and U_2, U_3 and U_4 is not linear but the results are however clustered. The predetermined outliers do not form any relationship with the clusters and are outside of the cluster.

Again, how does this assist with benchmarking? A reasonable approach would be to position a utility within a cluster. An allowable deviation could be ascertained by management strategic objectives within a predetermined range – between A and A'.

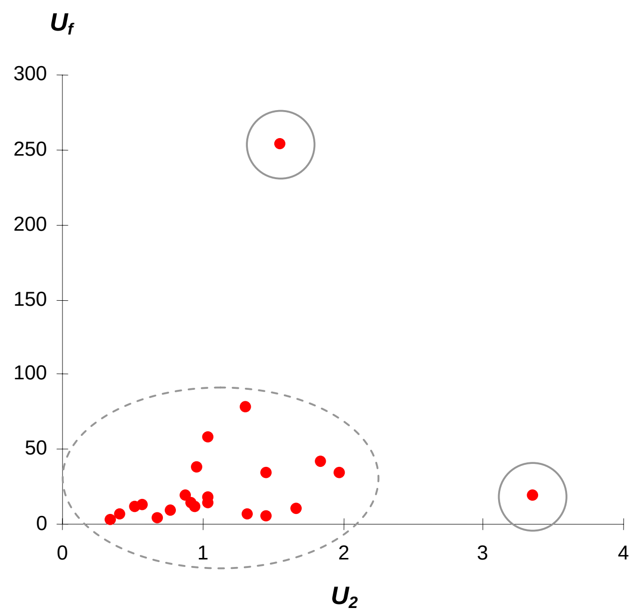


Figure 7.2: Scatter Plot for U_f and U_2.

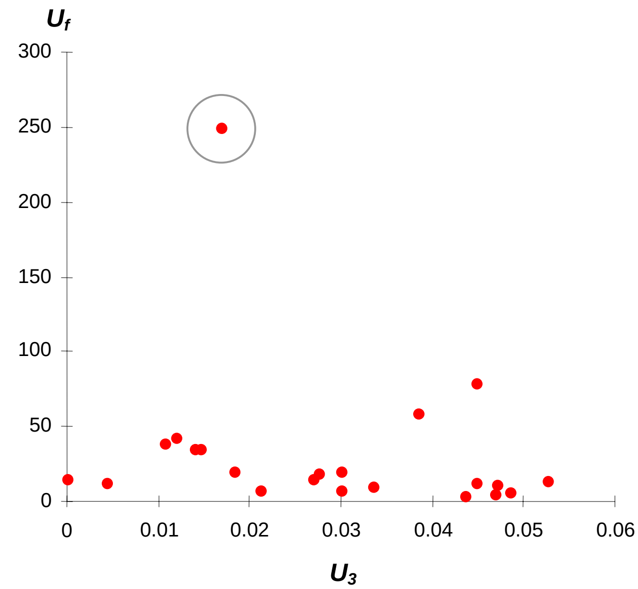


Figure 7.3: Scatter Plot for U_f and U_3.

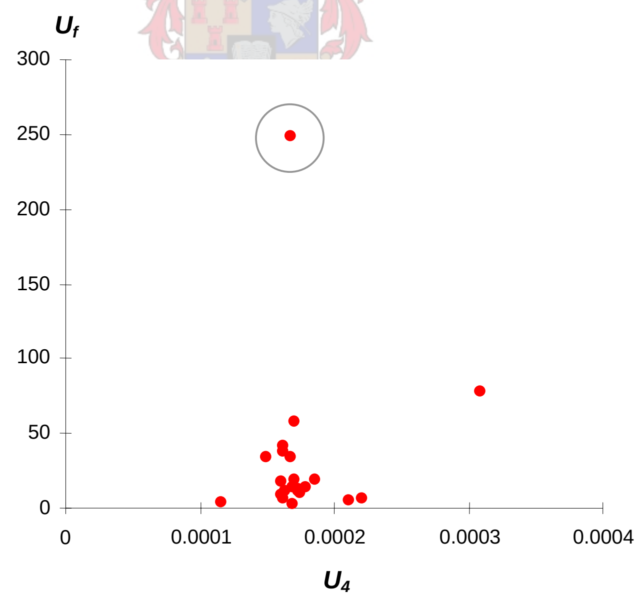


Figure 7.4: Scatter Plot for U_f and U_4.

7.3 Primary Variable "Reliability"

Following from *Chapter 6: Primary Variable "Reliability" Under Discussion, Section 5.6 Summary* (p6.50). The final equation derived from the comparison between the principal component analysis and the factor analysis was:

***Reliabilit*y Component (*R*) = 0.707 R_1 + 0.501 R_2 + 0.895 R_3 + 0.825 R_4** … [7.3]

For simplicity the above factor loading are modified to a total *weighting of 1*. This produces the following linear equation:

***Reliability* Component (R_f) = 0.241 R_1 + 0.171 R_2 + 0.306 R_3 + 0.282 R_4** … [7.4]

What is concluded is that for the utilisation component of the overall utilisation measurement index, the above forms one dimension of the three dimension index. The other dimensions to be concluded are the reliability and exogenous dimensions. However, the research is not concluded until the following is answered:

"How does linear equation 7.4 relate to the original data obtained in *Chapter 5: Primary Variable "Reliability" Under Discussion, Table 5.3: Raw Data Processed Without Masking the Outlier*" [p5.32].

Table 7.2: Reliability Data Processed Without Outlier Masking represents the original raw data and the single components of linear equation 7.4, and R_f represents the final summed value. The bolded italic values represent the original outliers as identified by the Box Plot in *Chapter 5: Primary Variable "Reliability" Under Discussion, Figure 5.4: Summary of Box Plot R Values* (p4.33). Thereafter, each component is separately plotted against the final value (R_f) to determine the relationship – linear or cluster? To facilitate referencing, the variables are repeated below.

- System minutes / maximum demand (MW) [R_1].
- System minutes / total MWh [R_2].
- Number of interruptions / maximum demand (MW) [R_3].
- Number of interruptions / total MWh [R_4].
- Primary *Reliability* component (index with no units) [R_f].

Table 7.2: Reliability Raw Data Processed <u>Without</u> Outlier Masking.

Utility	***Original Raw Data***				***Components of Equation 7.2***				***R_f***
	R_1	***R_2***	***R_3***	***R_4***	***$0.241R_1$***	***$0.171R_2$***	***$0.306R_3$***	***$0.282R_4$***	
E1	8.43E-07	***0.4171138***	0.0177259	3.91E-06	2.03E-07	7.13E-02	0.0054241	1.10E-06	7.68E-02
E2	0.0003689	6.42E-08	0.0253007	4.40E-06	8.89121E-05	1.10E-08	0.007742	1.24E-06	7.83E-03
E3	0.0007048	***1.26E-07***	0.0394286	7.07E-06	0.000169847	2.16E-08	0.0120652	1.99E-06	1.22E-02
E4	0.0004775	7.75E-08	0.0205312	3.33E-06	0.000115075	1.33E-08	0.0062825	9.40E-07	6.40E-03
E5	0.0003689	6.41E-08	***0.1708172***	***2.97E-05***	8.89145E-05	1.10E-08	0.0522701	8.37E-06	5.24E-02
E6	0.0010706	1.81E-07	0.0621698	1.05E-05	0.000258003	3.09E-08	0.019024	2.96E-06	1.93E-02
E7	0.0003002	4.93E-08	0.0115886	1.90E-06	7.23434E-05	8.43E-09	0.0035461	5.37E-07	3.62E-03
E8	0.000578	9.76E-08	0.0093931	1.59E-06	0.000139305	1.67E-08	0.0028743	4.48E-07	3.01E-03
E9	***0.0074104***	1.27E-06	0.0587443	1.01E-05	0.001785906	2.17E-07	0.0179758	2.84E-06	1.98E-02
E10	***0.0098096***	***3.04E-06***	0.0469854	1.45E-05	0.002364114	5.19E-07	0.0143775	4.10E-06	1.67E-02
E11	8.33E-05	1.55E-08	0.0061182	1.14E-06	2.00799E-05	2.64E-09	0.0018722	3.20E-07	1.89E-03
E12	0.0001353	2.19E-08	0.0252639	4.09E-06	3.26169E-05	3.74E-09	0.0077308	1.15E-06	7.76E-03
E13	0.0003512	7.42E-08	0.0218127	4.61E-06	8.46464E-05	1.27E-08	0.0066747	1.30E-06	6.76E-03
E14	0.0003577	6.24E-08	0.0093791	1.64E-06	8.61961E-05	1.07E-08	0.00287	4.61E-07	2.96E-03
E15	0.0003491	4.04E-08	0.0520704	6.02E-06	8.41235E-05	6.91E-09	0.0159335	1.70E-06	1.60E-02
E16	0.0001577	2.36E-08	0.0115344	1.73E-06	3.80009E-05	4.03E-09	0.0035295	4.86E-07	3.57E-03
E17	0.0004084	6.56E-08	0.0378668	6.09E-06	9.84172E-05	1.12E-08	0.0115872	1.72E-06	1.17E-02
E18	***0.0014779***	2.39E-07	0.0135896	2.20E-06	0.000356181	4.09E-08	0.0041584	6.20E-07	4.52E-03
E19	1.85E-05	3.11E-09	0.0096958	1.63E-06	4.4626E-06	5.31E-10	0.0029669	4.59E-07	2.97E-03
E20	2.74E-06	4.60E-10	0.0250781	4.22E-06	6.594E-07	7.87E-11	0.0076739	1.19E-06	7.68E-03
E21	3.53E-08	3.53E-08	0.0530841	8.54E-06	8.51116E-09	6.04E-09	0.0162437	2.41E-06	1.62E-02
E22	7.02E-10	***3.3595018***	0.0060656	1.03E-06	1.69286E-10	5.74E-01	0.0018561	2.91E-07	5.76E-01

Figure 7.5: Scatter Plot for R_f and R_1. indicates a clustering of values at the origin. The visible outliers are encircled. The outlier on the R_f axis is a derivative from the equation and not from the R_1 values, but rather from the R_2 values (E_{22}). Another explanation for the relative close clustering of R_2, is that the outliers obscure the scale.

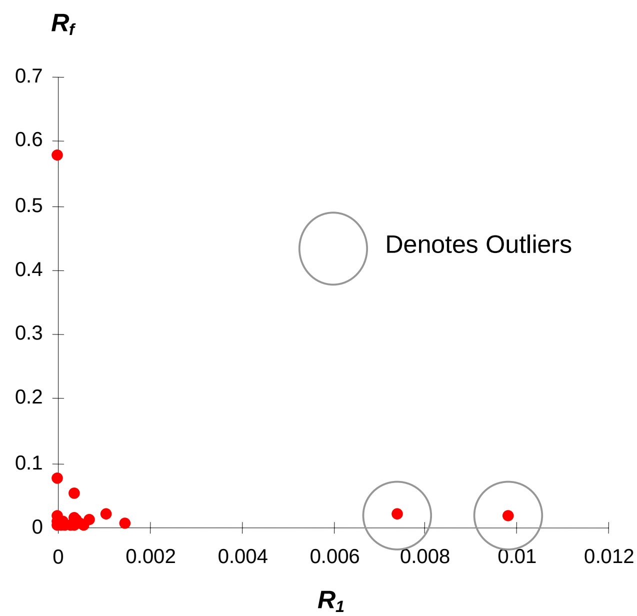


Figure 7.5: Scatter Plot for R_f and R_1.

Figure 7.6: Scatter Plot for R_f and R_2 indicates a clustering of values at the origin. The visible outliers are encircled.

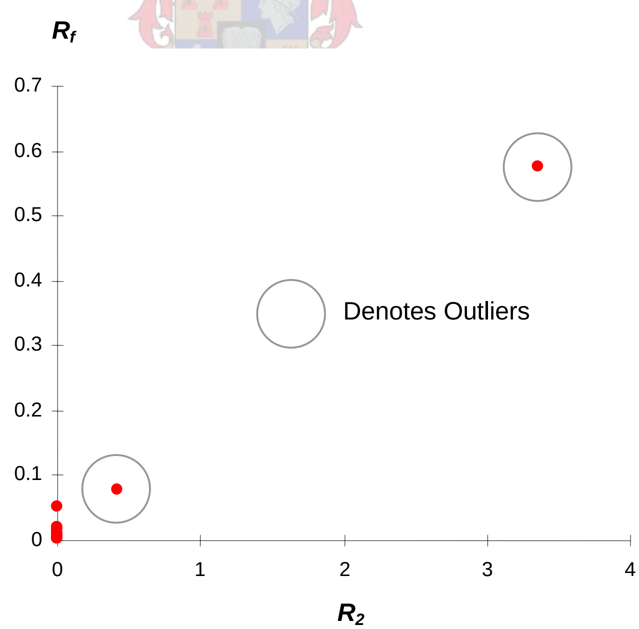


Figure 7.6: Scatter Plot for R_f and R_2.

Figure 7.7: Scatter Plot for R_f and R_3. indicates a linearity of values. The visible outliers are encircled. As in the case for U_f and U_1, a reasonable approach would

be to position a utility along the linear relationship (solid grey coloured line). An allowable deviation could be ascertained by management strategic objectives within a predetermined range – between A and A'. The same would apply to *Figure 7.8: Scatter Plot for R_f and R_4.*

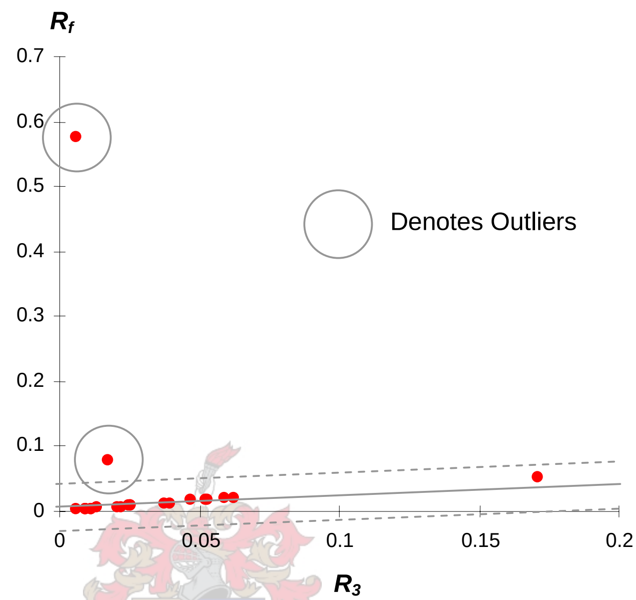


Figure 7.7: Scatter Plot for R_f and R_3.

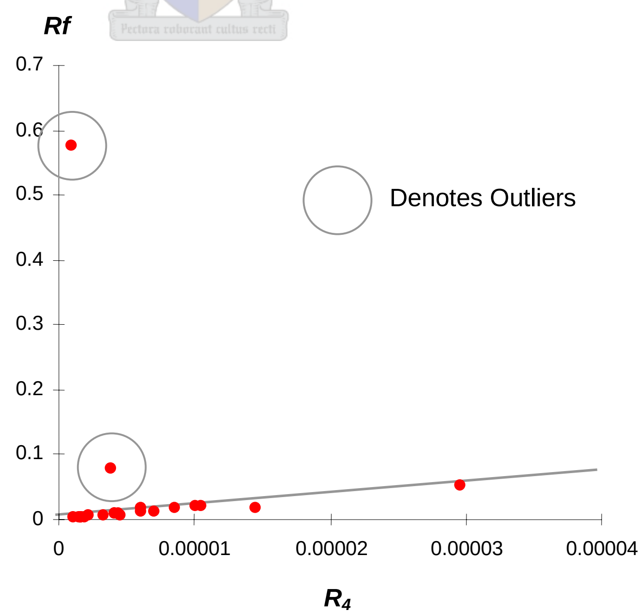


Figure 7.8: Scatter Plot for R_f and R_4.

7.4 Primary Variable "Exogenous"

Following from *Chapter 6: Primary Variable "Exogenous" Under Discussion, Section 6.6 Summary* (p6.25). The final equation derived from the comparison between the principal component analysis and the factor analysis was:

***Exogenous* Component (*E*) = 0.928 E_1 + 0.742 E_2 + 0.918 E_3** … [7.5]

For simplicity the above factor loading are modified to a total weighting of 1. This produces the following linear equation.

***Exogenous* Component (E_f) = 0. 359 E_1 + 0.287 E_2 + 0.354 E_3** … [7.6]

What is concluded is that for the exogenous component of the overall utilisation measurement index, the above forms one dimension of the three dimensional model. The other dimensions to be concluded are the reliability and utilisation dimensions. However, the research is not concluded until the following is answered:

"How does linear equation 7.6 relate to the original data obtained in *Chapter 6: Primary Variable "Exogenous" Under Discussion, Table 6.3.2 Raw Data Processed*" [p6.12].

Table 7.3: Exogenous Data Processed represents the original raw data and the single components of linear equation 7.6, and E_f represents the final summed value. There were no outliers in the *exogenous* data of *Chapter 6: Primary Variable "Utilisation" Under Discussion, Section 6.6 Summary (p6.29).* Thereafter, each component is separately plotted against (E_f) to determine the relationship – linear or cluster. To facilitate referencing, the variables are repeated below.

- Per capita energy consumption (million tons oil equivalent / capita) [E_1].
- CO_2 emissions per capita (million tons / capita) [E_2].
- Gross Domestic Product / capita ($\$_{US}$ / capita) [E_3].
- *Exogenous* component (index with no units) [E_f].

Table 7.3: Exogenous Raw Data Processed.

Country	Original Raw Data			Components of Equation 7.3.1			E_f
	E_1	E_2	E_3	$0.359\ E_1$	$0.287\ E_2$	$0.354\ E_3$	
C_1	252.2	5.05	27012	90.5398	1.44935	9562.248	9654.237
C_2	355.4	5.63	35935	127.5886	1.61581	12720.99	12850.19
C_3	101.3	2.04	20660	36.3667	0.58548	7313.64	7350.592
C_4	164	2.51	25427	58.876	0.72037	9001.158	9060.754
C_5	210.4	2.24	19293	75.5336	0.64288	6829.722	6905.898
C_6	72.1	1.01	10340	25.8839	0.28987	3660.36	3686.534
C_7	250.6	2.51	26275	89.9654	0.72037	9301.35	9392.036
C_8	424.3	2.73	31601	152.3237	0.78351	11186.75	11339.86
C_9	417.7	5.02	28932	149.9543	1.44074	10241.93	10393.32
C_{10}	95.2	2.12	9529	34.1768	0.60844	3373.266	3408.051
C_{11}	251.3	1.77	25617	90.2167	0.50799	9068.418	9159.143
C_{12}	101.3	1.7	18048	36.3667	0.4879	6388.992	6425.847
C_{13}	104.7	2.37	9439	37.5873	0.68019	3341.406	3379.673

Figure 7.9: Scatter Plot for E_f and E_1 illustrates clustering along a linear trend. E_1 represents the per capita energy consumption (million tons / capita). A linear clustering can be expected as the energy consumption is normalized by the per capita. Although the energy consumption is the equivalent to million tons of coal, it does include all energy forms which are not specific to the generation of electricity. This addresses the trend towards clustering and not total linearity.

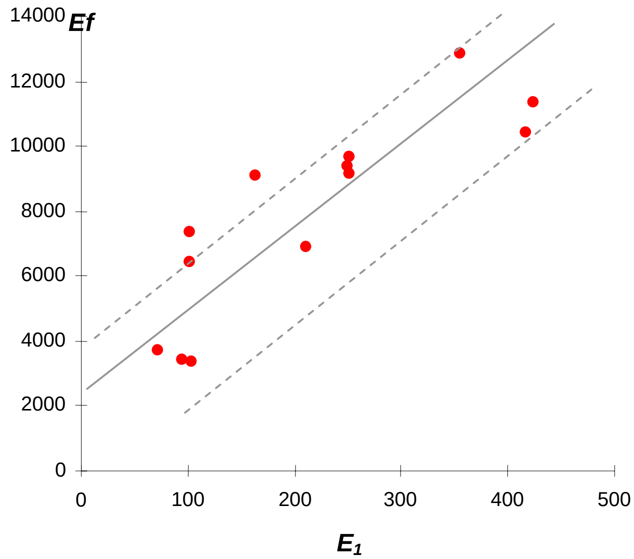


Figure 7.9: Scatter Plot for E_f and E_1.

The relationship CO_2 emissions per capita (million tons / capita) [E_2] and Gross Domestic Product / capita ($\$_{US}$ / capita) [E_3] both follow linear relationships. Again this is supported by the fact that all values have been nomalised with the denominator “per capita”.

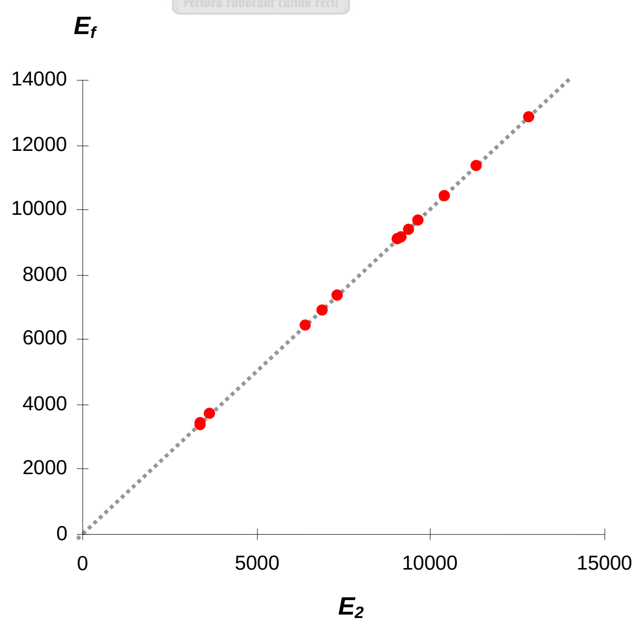


Figure 7.10: Scatter Plot for E_f and E_2.

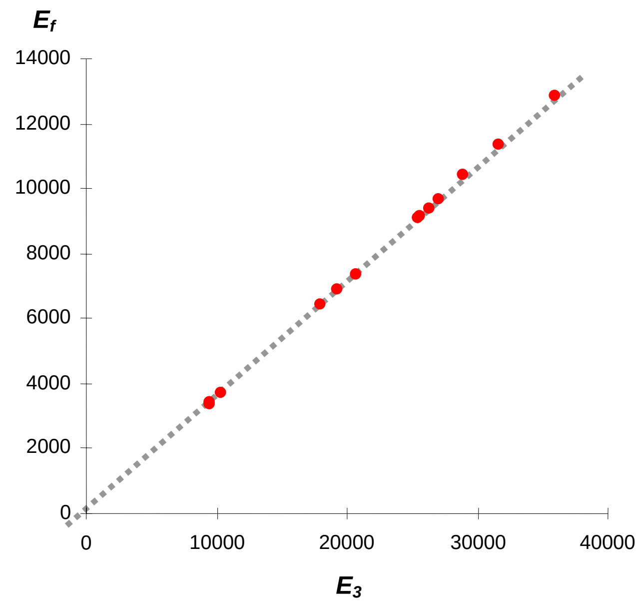


Figure 7.11: Scatter Plot for E_f and E_3.

In the production of electricity, fossil fuels (oil, natural gas and coal) are by far the dominant energy source - *Chapter 4: Primary Variable "Utilisation" Under Discussion, Section 4.6 Summary; Figure 4.2.2: World Consumption of primary energy (p4.8).* These produce proportionately the CO_2 emissions in the world.

7.5 3-Dimensional Representation of Composite Utilisation

From the derived primary variables for each electricity utility, a 3-Dimensional graphical model was composed to provide a relation between the three variables. The data as presented in Table 7.4: Summary of Primary variable Data was used to construct the 3-Dimensional model.

Uf	***Rf***	***Ef***
6.7795934	7.68E-02	9654.237
11.838141	7.83E-03	12850.19
13.204152	1.22E-02	7350.592
5.9437659	6.40E-03	9060.754
13.095693	5.24E-02	6905.898
3.0572498	1.93E-02	3686.534
11.264687	3.62E-03	9392.036
13.277651	3.01E-03	11339.86
57.359444	1.98E-02	10393.32
77.6303	1.67E-02	3408.051
18.838088	1.89E-03	9159.143
38.126544	7.76E-03	6425.847
4.4962663	6.76E-03	3379.673
9.9046538	2.96E-03	
4.1496055	1.60E-02	
33.709326	3.57E-03	
8.6768013	1.17E-02	
41.192081	4.52E-03	
248.68686	2.97E-03	
33.475859	7.68E-03	
17.845957	1.62E-02	
18.312199	5.76E-01	

This 3-Dimensional Model is illustrated in *Figure 7.12: 3-Dimensional Plot of Primary Variables (U_f, R_f and E_f).*

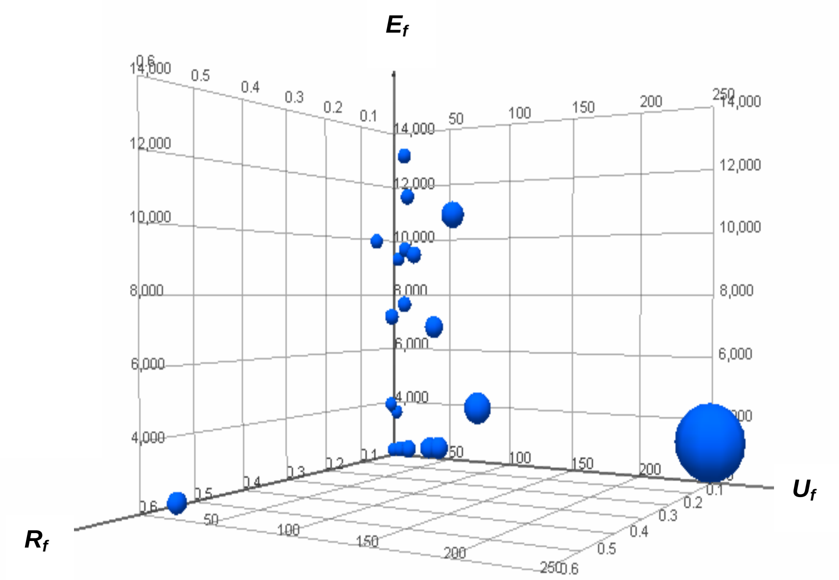


Figure 7.12: 3-Dimensional Plot of Primary Variables (U_f, R_f and E_f).

The application of this 3-Dimensional model can be questioned as a uniform matrix does not exist. The model would have been more representative should there have been a 22 x 3 matrix.

However, the model does show some interesting trends. Most utilities are positioned along the E_f axis with a concentration around the origin being the ideal position. *See Chapter 8:Application of the Transmission Network Utilisation Index.*

7.6 Conclusion

The transmission electrical network utilisation index can be utilised by electric utilities for different applications. The main application would be benchmarking. An electric utility can measure itself against other electric utilities. An additional application would be to establish a milestone within the same organisation, and measure future trends. This would then provide performance trends for planning, network expansion, and operations and maintenance.

The desired position for any electric utility would be that U_f, R_f and E_f be as close to the origin as possible. In addition, the secondary values (U_1, U_2, U_3, U_4, R_1, R_2, R_3, R_4, E_1, E_2, *and* E_3) should also be as close to the origin as possible. However, this is not possible as there are increasing relations within the chosen measurements. An example is Energy Losses (MWh)/Total Energy (MWh) [U_3]. It can be expected that the higher the energy transferred, the higher the energy losses will be. All of the secondary measures within each of primary variables (U_f, R_f and E_f) have been selected with the lowest value in each case being the desired performance target. It is neither practical or affordable to have zero as a desired performance target. Electric utilities that are on the high end of the extended linear line or cluster, should strive towards a lower value for an improvement in performance.

Chapter 8

APPLICATION OF THE TRANSMISSION NETWORK UTILISATION INDEX

Chapter Objective

This chapter's objective is to provide an insight into the contribution this research has on the performance measurement of electricity utilities. It attempts to answer the "who benefits and why" from the research study. It provides a practical aide for senior management and engineers to evaluate the operational state of the organization in terms of utilisation and reliability. If required, the socio-economical dimension may also be assessed. The individual primary variables are considered as well as the secondary primary variables.

8.1 Overview

It must be noted that this research is based on specific performance variables which have been selected by the researcher during the research process. However, the researcher acknowledges that the suitability of these variables may be debated by certain organisations which have different performance measurement priorities. This is accepted - as the research study has not only been the derivation of a composite utilisation index, but also a process by which any variable, or number of variables may be considered. Furthermore, it must be emphasised that any organisation has a multitude of performance measures options by which it may measure itself. These may also change over a period of time according to changing priorities. Lastly, it must be noted that the researcher has derived the measurement index from specific electricity utilities. For different performance measures it may be more appropriate to be selective in the number and representation of the benchmarked electricity utilities. For example, why would a developing country in Africa benchmark itself against a large representation from industrialised countries? A comparison study with a smaller sample of industrialised countries and larger sample of developing countries would be more appropriate. Similarly, why would an industrialised country compare itself to a developing country which does not have a comparative transmission network?

8.2 Comparison Options from the Derived Index

The previously derived equations 7.1.1; 7.2.1 and 7.3.1 offer various comparative options. These include, but are not conclusive, of the following:

- The measurement and benchmarking of individual primary variables – i.e. U_f, R_f and E_f.
- The measurement and benchmarking of individual secondary variables – i.e. U_1, U_2, U_3, U_4, R_1, R_2, R_3, R_4, E_2, E_2, and E_3.
- The collective benchmarking of all three primary variables – i.e. U_f, R_f and E_f in a 3-dimensional graphical model.

The following is a discussion on how an electric utility may apply the derived transmission network utilisation index. The practical example focuses on one of the selected 22 electricity utilities that have been included in the research study. The electricity utility under consideration is E_6. It therefore assumes that the chosen variables and the sample size and representation for comparison are aligned with this research study.

8.3 Measurement & Benchmarking of Individual Primary Variables

Of the three primary variables, the researcher has randomly chosen *reliability* to demonstrate the application.

Assume electricity utility E_6 has deemed it necessary to benchmark itself against 21 electricity utilities for the following reasons:

- To ascertain, from an international performance point of view, where E_6 is positioned regarding reliability (R_f) as selected within the scope of this study.
- Once its positioning is determined, E_6 is to develop management strategies and performance targets which will align itself within the top five performing benchmarked electricity utilities.

Firstly, one must determine: what is the most favourable position for a top performing utility – a high or low value? The answer is in reviewing the four secondary variables.

- System minutes / maximum demand (MW) [R_1].
- System minutes / total MWh [R_2].
- Number of interruptions / maximum demand (MW) [R_3].
- Number of interruptions / total MWh [R_4].

An electricity utility with the lowest value in all four of these secondary variables will be the overall best performer. Therefore, the best performing electricity utility will strive to attain the lowest value of R_f.

The data range for R_f is between 1.89E-03 and 5.76E-01. Utility E_6 is positioned at a value of 1.93E-02. The significance of these values may not be realised unless they are graphically presented. All the values derived for R_f in *Chapter 7: Discussion Emanating from the Research* are illustrated in *Figure 8.1: Reliability (R_f) Data Processed <u>Without</u> Outlier Masking*.

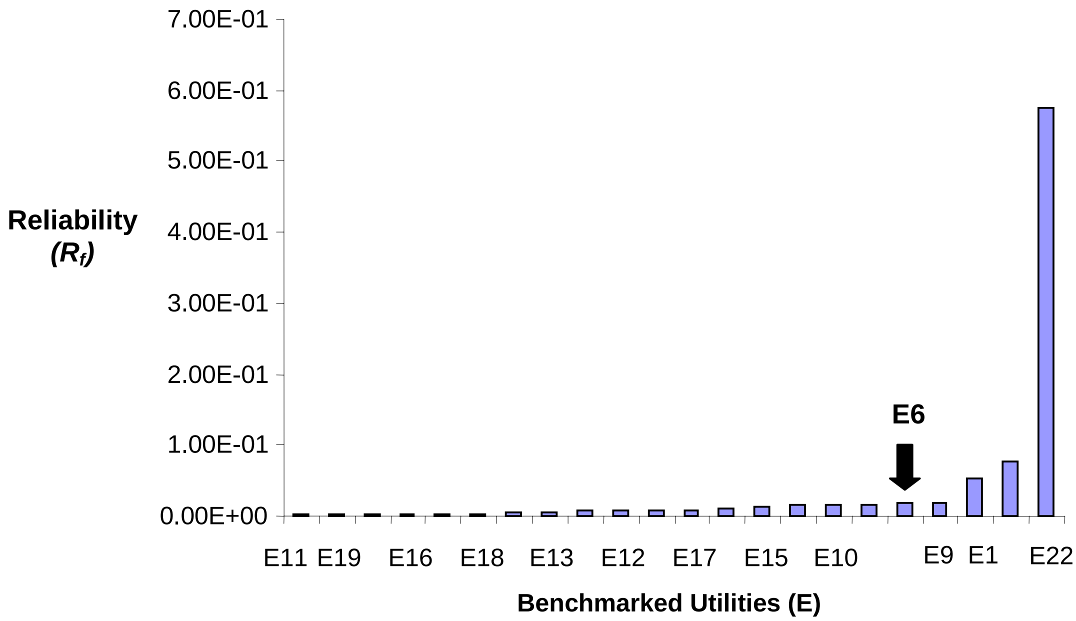


Figure 8.1: Reliability (R_f) Data Processed <u>Without</u> Outlier Masking.

The above shows that the performance data is heavily skewed or biased in the direction of the last three electricity utilities (E5, E1 and E22). A simple box plot reveals that these three utilities are outliers. The Reliability *(R_f)* values 0.576, 0.0768, and 0.0524, are eliminated from the above figure. Subsequently, this produces *Figure 8.2: Reliability (R_f) Data Processed <u>With</u> Outlier Masking*. The distribution of values are now more acceptable.

Revisiting the assumed improvement statement of: "Once it's positioning is determined, E_6 is to develop management strategies and performance targets which will align itself within the top five performing benchmarked electricity utilities." To be *one of the top five international electricity utilities* can be an organisation's mission statement or strategic objective. The improvement required is visible in *Figure 8.3: Setting the Reliability (R_f) Performance Targets*.

It must be remembered that the data collected is over a period of five years. This prevents the collection of "exceptional" or "unrealistic" data experienced by electricity utilities during periods as short as a year. A, typical example is the extreme conditions experienced in North America during the late 1990's.

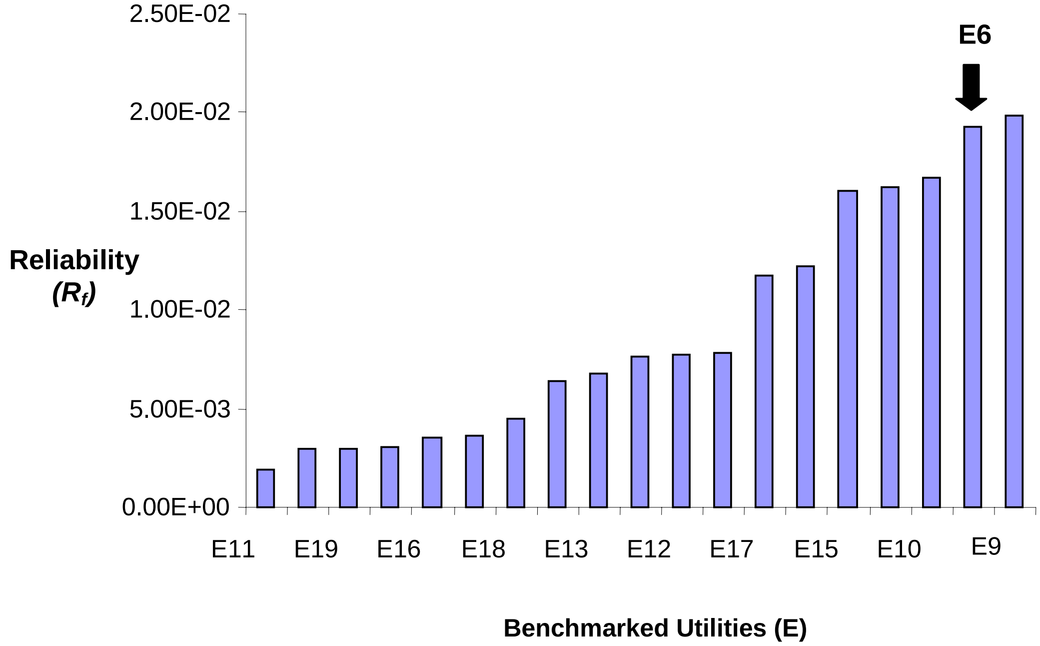


Figure 8.2: Reliability (R_f) Data Processed With Outlier Masking.

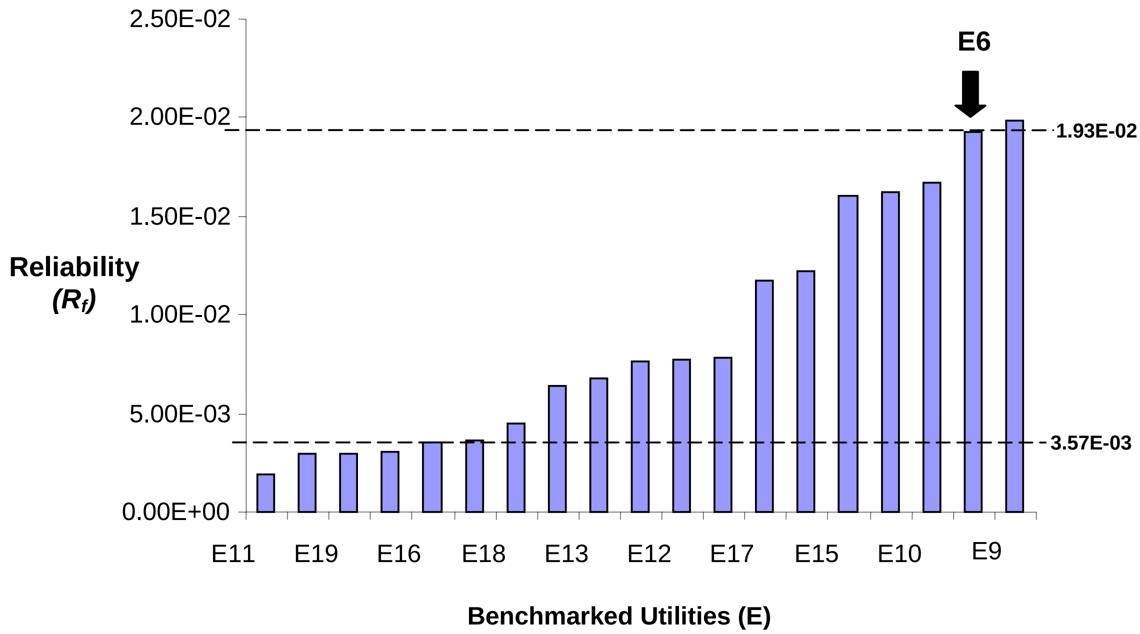


Figure 8.3: Setting the Reliability (R_f) Performance Targets.

Once the target for reliability (R_f) of 3.57E-03 is established, a strategy to realise this target must be forthcoming. During this process equation 8.1 must be revisited and the impact of each of the secondary variables considered.

Reliability **(R_f) = 0.241 R_1 + 0.171 R_2 + 0.306 R_3 + 0.282 R_4** … 8.1

R_1 and R_2 contain the performance measure of system minutes. These two secondary variables can be improved on by reducing the supply restoration time. Improvement strategies such as emergency preparedness plans, skills development, and where financial resources allow, the expansion or refurbishment of transmission networks can be applied.

However, the total "weight" of improving R_f in this area of R_1 and R_2 is only 41.20%. Whereas, the remaining two secondary variables (R_3, R_4) are weighted at 58.80%. R_3 *and* R_4 contain the performance measure of a number of interruptions. The number of interruptions can be improved on by maintaining or replacing troublesome plant and equipment, reviewing protection settings, inactivating auto-reclosure mechanisms, and the introduction of environmental management control systems (sugar cane burning and bird deterrents). The above strategies are not conclusive, and it is not the intent of this research study to detail performance improvement strategies.

The above process can be applied to the exogenous (E_f) primary variable as all three secondary variables have favourable results when decreasing. What must be realised is that the utilisation (U_f) primary variable is different. All the secondary utilisation variables (U_1, U_2, U_3, U_4) may be considered favourable if the results have either an increasing or decreasing trend. How so? An electricity utility may be under utilising its assets, and therefore look to a higher utilisation as the desired performance end state. Alternatively, an electricity utility that is over utilising its assets may require a lower utilisation as the desired performance end state.

Furthermore, if an electricity utility benchmarks itself and finds itself to be an outlier, then significant improvement in performance levels are required. In all other circumstances outliers are disregarded from the comparison.

8.4 Measurement & Benchmarking of Individual Secondary Variables

Assume electricity utility E_{22} has deemed it necessary to benchmark itself against 21 electricity utilities for the following reasons:

- E22 is experiencing an increasing number of "load relief requests" due to the inability of the transmission lines to carry the required energy demanded during peak periods. As a result E22 deems it necessary to benchmark itself against 21 international utilities. The utilisation secondary variable applicable is Maximum Demand (MW)/Length of Transmission Lines (km) [U_2].

The results are illustrated in *Table 8.1: Benchmarked U_2 Results*.

Table 8.1: Benchmarked U_2 Results.

Utility	U_2
E_1	0.0955159
E_2	0.119996
E_3	0.2106571
E_4	0.3021197
E_5	0.133049
E_6	0.0806538
E_7	0.2175729
E_8	0.2378394
E_9	0.2383203
E_{10}	0.3005625
E_{11}	0.2023444
E_{12}	0.2217407
E_{13}	0.333653
E_{14}	0.3822926
E_{15}	0.1547582
E_{16}	0.452733
E_{17}	0.1788032
E_{18}	0.4216806
E_{19}	0.3506448
E_{20}	0.3346377
E_{21}	0.2375417
E_{22}	0.7693255

After performing a box plot, it is clear that E_{22} with a U_2 of 0.7693255 is the only outlier. The significance of this difference is graphically illustrated in *Figure 8.4: Benchmarked U_2 results.*

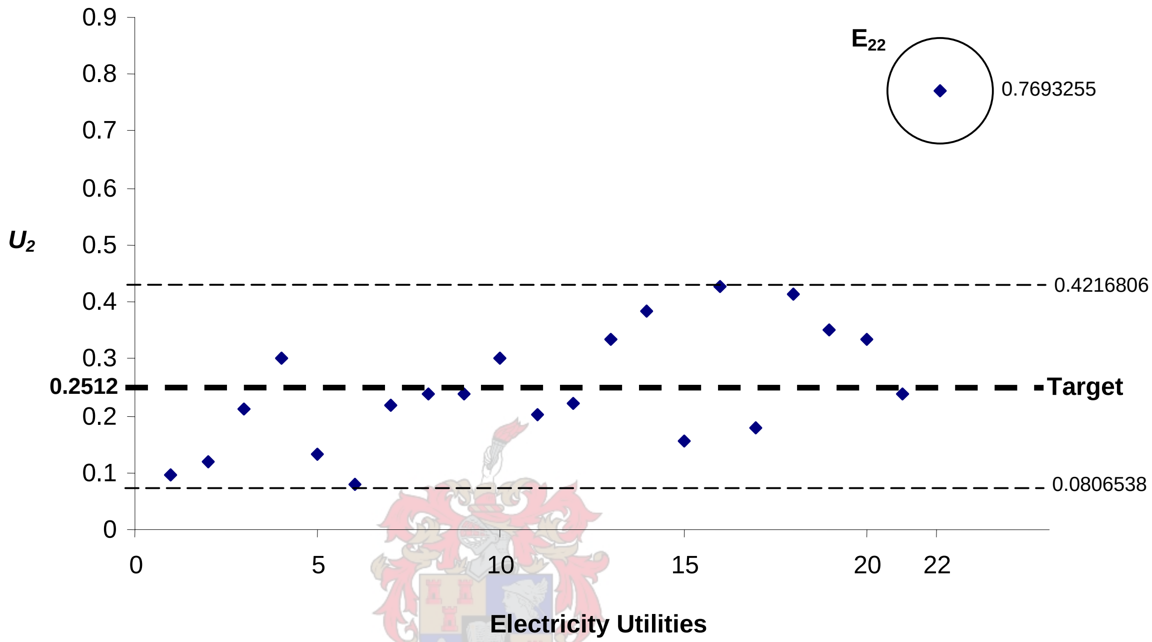


Figure 8.4: Benchmarked U_2 Results.

Improvement strategies are numerous. Once again, assuming E_{22} management and transmission engineers may take an assertive stance, and position themselves midway between the two extremes (outlier excluded). The desired U_2 would then be 0.2512. The positioning would depend on the resources available to carry out expansion plans or refurbish existing transmission lines.

8.5 Benchmarking of all 3 Primary Variables

An electricity utility may benchmark itself against the 3-Dimensional Model of all three primary variables. The particular number of electricity utilities should ideally correspond with the number of countries to facilitate comparison. This is not the case with the number of utilities and countries under this research study. An alternative approach would have been to include the number of countries more than once in *Table 8.2: Primary Variable Data.* This was not undertaken as to retain the original data format.

Table 8.2: Primary Variable Data.

Uf	***Rf***	***Ef***
6.7795934	7.68E-02	9654.237
11.838141	7.83E-03	12850.19
13.204152	1.22E-02	7350.592
5.9437659	6.40E-03	9060.754
13.095693	5.24E-02	6905.898
3.0572498	1.93E-02	3686.534
11.264687	3.62E-03	9392.036
13.277651	3.01E-03	11339.86
57.359444	1.98E-02	10393.32
77.6303	1.67E-02	3408.051
18.838088	1.89E-03	9159.143
38.126544	7.76E-03	6425.847
4.4962663	6.76E-03	3379.673
9.9046538	2.96E-03	
4.1496055	1.60E-02	
33.709326	3.57E-03	
8.6768013	1.17E-02	
41.192081	4.52E-03	
248.68686	2.97E-03	
33.475859	7.68E-03	
17.845957	1.62E-02	
18.312199	5.76E-01	

An electricity utility can position itself within the 3-Dimensional model representing three primary variables illustrated in *Figure 8.5: 3-Dimensional Model of Primary Variable Data.* The majority of results are scattered along the E_f axis as indicated within the oval.

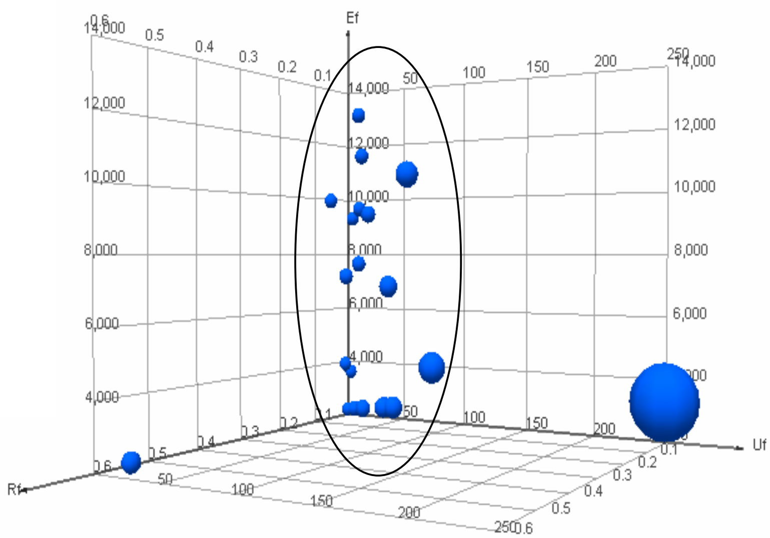


Figure 8.5: 3-Dimensional Model of Primary Variable Data.

Figure 8.6: 3-Dimensional Model of Primary Variable Data, illustrates the outliers (arrowed), and a further clustering around the origin of the U_f axis (within the oval).

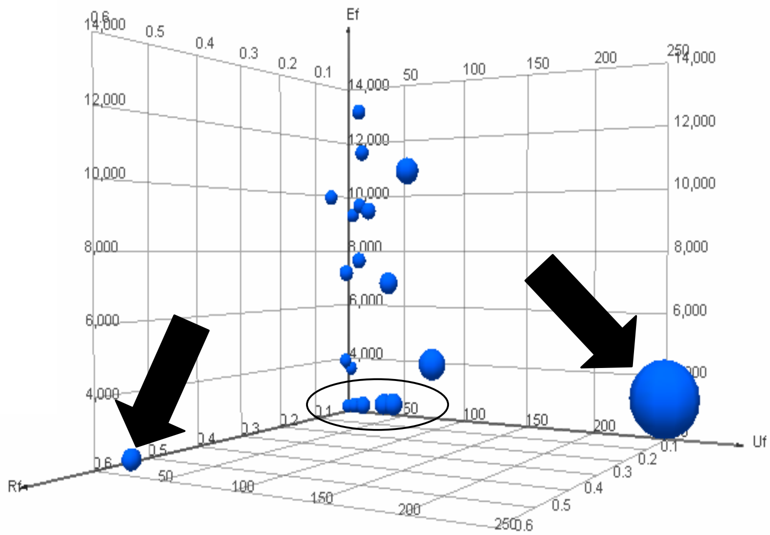


Figure 8.6: 3-Dimensional Model of Primary Variable Data.

Typically an electricity utility would be ideally positioned when it is within the lower oval as indicated in *Figure 8.6: 3-Dimensional Model of Primary Variable Data*. Why? As previously indicated, the ideal performance result would be at the lowest value within all performance measures. This is represented at the origin of all three variables (U_f, R_f and E_f).

8.6 Conclusion

The transmission electrical network utilisation index can be utilsed by electric utilities for different applications. The main application would be benchmarking. An electric utility can measure itself against other electric utilities. An additional application would be to establish a milestone within the same organization, and measure future trends. This would then provide performance trends for planning, network expansion, and operations and maintenance.

The desired position for any electric utility would be that U_f, R_f and E_f be as close to the origin as possible. In addition, the secondary values (U_1, U_2, U_3, U_4, R_1, R_2, R_3, R_4, E_1, E_2, *and* E_3) should also be as close to the origin as possible. However, this is not possible as there are increasing relations within the chosen measurements. An example is Energy Losses (MWh)/Total Energy (MWh) [U_3]. It can be expected that at the same transmission voltage, the higher the energy transferred, the higher the energy losses will be. All of the secondary measures within each of primary variables (U_f, R_f and E_f) have been selected with the lowest value in each case being the desired performance target. It is neither practical or affordable to have zero as a desired performance target. Electric utilities that are on the high end of the extended linear line or cluster, should strive towards a lower value for an improvement in performance.

Results benefit who and why? The results and application of this research study can directly benefit the electricity utility. This is achieved by the setting of realistic performance measures which will lead to the operational effectiveness of an organisation. Customers will ultimately gain due to the cost benefits which can be derived from the application of this performance improvement process regarding transmission network utilisation.

Chapter 9

CONCLUSION

<u>*Chapter Objective*</u>

This chapter's objective is to revisit and answer the initial primary and secondary research question. Furthermore it raises questions emanating from this research which are possible initiatives to further studies. Continuing research subjects are identified. The chapter concludes with the contribution this research can make within the electricity utility industry.

9.1 Overview

Research is initiated through inspiration and inspiration stems from the desire to follow and develop the teachings of great intellectuals, or to change a current situation. This research study has been inspired by both. The enthusiastic teachings of John Elkington in his book titled "Cannibals with Forks", was an inspiration. Remote from the traditional mathematical engineering research, this research project extended itself beyond the boundaries of usual experimental laboratories, measurements on electrical networks and computer-aided simulation.

The assessment of technology in engineering research is not only limited to the specific research project results, but also the assessment of such research to the aggregated technologies within the total environment. Over the past decades technology has always been the driver of economic progress. However, the researcher believes the future of technology research will be more "market driven" and within diminishing financial research funding.

Although far from being conclusive, or possibly comprehendible to the more ardent scholar, this research study has been an attempt to assess and benchmark the efficiency of transmission network utilisation. This has attempted to incorporate the factors mentioned in John Elkington's triple bottom line of 21st century business. Namely, affordability, social and environmental awareness.

9.2 Comments

Returning to the primary research question of Chapter 1: Background, section 1.2.3.1 (p1.8).

"How can a composite comparative study index for transmission electrical network utilisation be developed which is inclusive of utilisation, reliability and exogenous factors?"

The researcher believes the question has been addressed and a composite study index has been developed.

Returning to the secondary research question of *Chapter 1: Background, section 1.2.3.2 (p1.9).*

"*What are the relationships between the various primary variables? That is, between U_f, E_f and R_f?"*

Although a comparison between the primary inputs could not be finalised due to the difference in the sample size of utility and countries, the researcher believes that all primary comparative inputs are dependant on one another. This is supported by the fact that a "blackout" negatively affects the economy and has a negative social impact on the community. Inversely, the shutdown of a processing plant due to a "blackout" does have a minor impact on the environment – during the electricity power supply loss there are less CO_2 emissions in total.

9.3 Continuing Research

Questions emanating from this research are possible initiatives to further research studies. The following are identified as such subjects for research:

- In the production of electricity, fossil fuels (oil, natural gas and coal) are by far the dominant energy source - *Chapter 4: Primary Variable "Utilisation" Under Discussion, Section 4.2.1, Figure 4.3: World Consumption of primary energy (p1.18).* It is assumed that industrial and energy producing CO_2 emissions are proportionately contributors in the world. This could be continuing research to investigate the contribution industry has to contributing CO_2 emissions compared to the production of electricity.

- The question policy-making managers must ask is … "does the risk to the share equity value not exceed the capital costs to expand or refurbish the transmission network?" The researcher believes that this must be considered in the expansion criteria decisions. Investment decisions based on traditional economic evaluation must be expanded to include the affects major system disturbances have on the share equity value.

- This research presents an initial model for representing a "non-financial" balance sheet. Although not conclusive, this model represents only plant and equipment. It assumes that asset evaluation is based on the following:

  Utilisation (U) $\propto$ Life Expectancy (L) – Risks (R)

  U is synonymous to the *equity* value in a financial balance sheet. L is synonymous to the *asset* value and R to the *liabilities*. It assumes the net worth of any utility is its capacity to deliver the required energy demanded, given the remaining life expectancy of its network and anticipated operational risks. Risks are considered as a negative component of the equation. Risk includes the loss of engineering resource skills. The current value of an item of plant is its remaining life expectancy. The model derives its simplicity from the financial equivalent of the balance sheet. The author is aware of the possibility of many alternative models and that the proposed can become the centre of passionate debate. The proposed model forms a base from which further research can be initiated.

- This study only conceptualises the basics and the benefits of extended cost-benefit theory. To gain benefit from this, the challenge would be to realistically quantify the cost-benefit curves. The derived curves would be subjective and speculative as a percentage of the quantitative analysis is based on customer perceptions on the value of services. There are three cost-benefit scenarios to be considered. These are uniform, decreasing and increasing rate of change cost-benefit. These curves form a base from which further research can be initiated.

- The researcher's personal belief is that reliability demands (both from a continuity and a quality point of view), will increase across a more diverse customer base and not be limited mainly to industrial customers. This is accompanied by the further belief that the future expectations regarding reliability of transmission networks will achieve stability within the short-term, while the demands for improved reliability will increase for distribution networks. Trends in this regard can be investigated.

9.4 Concluding Remarks

Engineering research is continuing to extend itself beyond the boundaries of experimental laboratories. Not only is technology assessment strategic in engineering research, but so is the efficiency assessment of these aggregated technologies. Over the past decades technology has always been the driver of economic progress. However, the researcher believes the future of technology research will be become more and more "market driven" within diminishing financial funding. Although far from being conclusive, or possibly sensible to the ardent scholar, this research study has been an attempt to ascertain a benchmarking technique for the utilisation of transmission network.

A fair conclusion would be to state that there are more questions stemming from this research subject than what have been answered. Disheartening or inspiring? The researcher believes this study should be an inspiration for the further development of both the continuing interrelationship between engineering and other social affecting disciplines, e.g. economics, environment and politics. The recent blackout occurrences around the world should be viewed as a “wakeup-up call” for the industrialised world. Our dependency on electricity as a daily energy source will probably continue far into the future. The main question to be asked is … “are we not expecting too much from our existing transmission networks?” Have our expectations of technology not become obscured by the developments in information technology – faster and more capacity in less volume? We have become “micro focused” forgetting the panoptic vision of the millions of tons of oil equivalent that is consumed each year to provide us with our daily living requirements. In perspective, our daily living requirements in the industrialised world (and specifically city dwellers), is many times more than the *basic* needs of the vast majority of the world’s population. *Are we not then fortunate to have only one major blackout in five to eight years?* Try convincing the average electricity consumer of this statement when all electricity utilities are to be privatized and managed solely by professional accountants and owned by shareholders!

And a second important question … “should political policy makers not focus more on the expansion and refurbishment of transmission networks before committing billions of dollars on life destroying assignments – and estimated $800 billion for global military spending?”

As advisers, engineers cannot answer these questions but can provide the expertise to improve technical performance so that communities are guaranteed a sustainable supply of electricity. It is the intent of the researcher that the “*derivation of a composite transmission network utilisation index”* addresses this issue and provides a stepping stone for the future development in electric utility performance measurement. This input can be a valuable input into the repeated *Figure 1.3: Performance Improvement Strategies* of *Chapter 1: Background information (p1.18).*

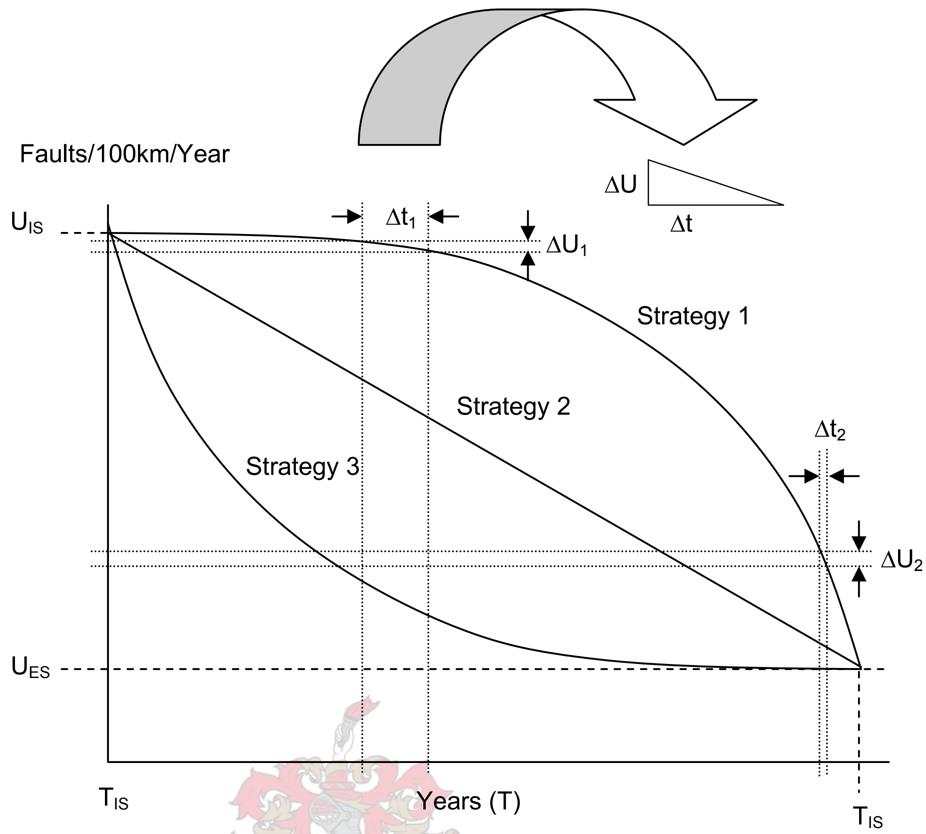


Figure 1.3: Performance Improvement Strategies

In conclusion – this research has provided a transmission utilisation index for benchmarking the selected electricity utilities. As demonstrated in *Chapter 8: Application of the Transmission Network Utilisation Index*, the research provides a template for a process for the derivation of a transmission utilisation index. This process can be applied should other countries or electricity utilities be considered other than those selected in the research study. Furthermore, the process may be applied for the application of other performance measures an organisation may deem necessary.

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Appendix 1:

EXAMPLE OF ELECTRICITY UTILITY RAW DATA

Example of raw data received during the participation in the National Grid International Comparison of Transmission Performance.

	1995	1996	1997	1998	1999
TECHNICAL					
No. of transmission circuit km	25325	24765	26460	26460	26460
Planned transmission circuit outages	387	407	396	415	423
Forced transmission circuit outages	44	351	880	1032	1034
Total transmission circuit outages	431	758	1276	1447	1457
Transmission faults (less than 1 hour)	272	273	707	861	725
Transmission faults (greater than 1 hour)	310	236	202	233	345
Total transmission faults	582	509	909	1094	1070
Average duration of fault outages Hours	16.1	10.20	10.54	12.4	16.6
Circuit hours not available (planned)	62464	61463	63923	67083	68288
a) Maintenance					
b) Development					
Circuit hours not available (forced)	9601	7856	9581	13568	17762
Total circuit hours not available	72065	69319	73504	80651	86048
Total no. of circuit hours available	6372160	6231255	6301708	6331567	6342836
MWh not supplied	2004	3218	3068	2471	1524
MWh non-economic generation			14530000	14827000	15445000
MWh delivered from the transmission network	1.7E+08	1.75E+08	1.73E+08	173278567	1.77E+08
Total MWh demand	1.63E+08	1.79E+08	1.73E+08	171454000	1.73E+08
Total MWh.km	6.42E+00				
MWh losses	5749000	3130000	4697688	5371728	5121351
Maximum demand MW	27967	28329	28167	27965	27813
Interconnectors - MWh import	0	29	38625	2509623	6704409
Interconnectors - MWh export	162000	3379	5518615	3282658	2997547
No. of major disturbances	3	2	2	1	0
No. of unsupplied energy incidents	55	58	38	43	55

		1995	1996	1997	1998	1999
Background Information						
No. of substations	No.	116	170	160	160	160
	Average age (years)	17	14	15	16	17
	Gross book value	13049				
a) Circuit breakers	No.	2800	2800	2769	2769	2769
	Average age (years)		20	21	21	22
	Gross book value					
b) Transformers	Total no.	520	520	380	380	380
	Average age (years)		21	22	23	23
	Gross book value					
	MVA (Total)	1117512	130000	112910	112910	112910
(i)	No of bulk supply transformers	300	520	380	380	380
	Average age (years)		21	22	22	23
	Gross book value					
	MVA (Total)	1078342	130000	112910	112910	112910
(ii)	No of intergrid transformers	52				
	Average age (years)					
	Gross book value					
	MVA (Total)	39170	130000			
c) Transmission lines	Circuit km	25325	24765	26480	26480	26480
	Average age (years)		30	31	32	33
	Gross book value					
d) Transmission cables	Circuit km	0	0	0	0	0
	Average age (years)	n/a	n/a	n/a	n/a	n/a
	Gross book value	n/a	n/a	n/a	n/a	n/a
e) Other switchgear	Average age (years)		20	0	0	0
	Gross book value					
f) Protection, control & telecoms	Average age (years)		15	16	17	17
	Gross book value					
g) Series reactors	No.	0	0	0	0	0
	Capacity (MVAr)					
	Average age (years)					
	Gross book value					
h) Shunt reactors	No.	48	56	56	56	56
	Capacity (MVAr)		6560	6560	6560	6560
	Average age (years)					
	Gross book value					
i) Series capacitors	No.	15	4	3	3	3
	Capacity (MVAr)		500	500	500	500
	Average age (years)		25	26	27	28
	Gross book value					
j) Shunt capacitors	No.	70	60	60	60	60
	Capacity (MVAr)		5000	5000	5000	5000
	Average age (years)		25	26	27	28
	Gross book value					

Primary Technical Indicators

MWh delivered/MWh demanded	99.9988%	99.9982%	99.9982%	99.9986%	99.9991%
Unsupplied energy (system minutes)	4.30	6.82	6.54	5.30	3.29
MWh non-economic generation/MWh delivered	0.00%	0.00%	8.38%	8.56%	8.73%
Circuit availability	98.87%	98.89%	98.83%	98.73%	98.64%
Circuit outages/100 circuit km	1.70	3.06	4.82	5.47	5.51
Outages/circuit	0.59	1.07	1.77	2.00	2.01
No of faults/100 circuit km	2.30	2.06	3.44	4.13	4.04
Faults/circuit	0.80	0.72	1.26	1.51	1.48
Average duration of fault outages Hours	16.1	10.2	10.5	12.4	16.6
No of major disturbances	3	2	2	1	0

Secondary Technical Indicators

Circuit non-availability due to planned outages	0.98%	0.99%	1.01%	1.06%	1.08%
Circuit non-availability due to planned maintenance outages	0.00%	0.00%	0.00%	0.00%	0.00%
Circuit non-availability due to planned development outages	0.00%	0.00%	0.00%	0.00%	0.00%
Circuit non-availability due to forced outages	0.15%	0.13%	0.15%	0.21%	0.28%
Outages(planned)/100 circuit km	1.53	1.64	1.50	1.57	1.60