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The Effectiveness of Electricity Time of Use Tariffs in the Western Cape

by

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Submitted in fulfilment of the requirements for the degree

**Master of Science in Electrical Engineering
by Dissertation only**

in the

Faculty of Engineering & The Built Environment

University of Cape Town

Supervisor: Prof. Dr. T. Gaunt

November 2010

Declaration

I declare that

The Effectiveness of Electricity Time of Use Tariffs in the Western Cape

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Fagmie Essa	31 August 2010
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Abstract

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In South Africa, Time of Use (TOU) tariffs have been available to Eskom's customers since 1986. TOU tariffs are intended to encourage users to avoid using electrical energy during the periods at which the national electricity system is stressed during normal operating conditions, i.e. Peak periods.

It has not always been clear how customers were responding to the different types of Eskom tariffs. A study was done of Eskom's Large Power Users (LPUs) in the Western Cape province of South Africa. Customers were categorised into City of Cape Town (CCT), 2 types of KSACS customers, Agricultural, Non-Agricultural and Rural Municipalities. At least 30 customers within a category were selected as a sample of that category. Customers within a certain category were not necessarily all using electricity via the same tariff.

There are 2 aspects of TOU tariffs: seasonal and daily. The seasonal aspect encourages users to avoid the High demand season which coincides with South Africa's winter season. The rest of the year is considered the Low demand season. The daily aspect is divided effectively into a maximum of 3 periods: Off-peak, Standard and Peak.

It was found that KSACS customer (largest 3), CCT and Rural municipalities use more energy during the High demand season. KSACS customers (without the largest 3), Agricultural and Non-agricultural customers use more energy during the Low demand season.

It was further found that KSACS customers (largest 3) and KSACS customer (without largest 3, without the people rail component) have a distinct preference for the

cheapest period, the Off-peak period, during both seasons. These same customers registered the lowest average demand for the Peak period. Agricultural and Non-agricultural customers registered the highest average demand for the Standard period; the lowest average demands for these customers were registered for the Off-peak and Peak periods respectively. CCT, Rural municipalities and Eskom's residential customers registered their daily maximum demand during the evening Peak periods.

Residential customers have been identified in previous literature to cause the region, and the country as a whole, to peak during the Peak periods. The overwhelming majority of the WR's residential customers are not on a TOU tariff and they have no present incentive to change the way they consume electricity. Legislation has been proposed that high end users be converted to a type of TOU tariffs by 2012 while the Electrification-type (RDP housing) customers should rather benefit from Electricity Efficiency initiatives.

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List of abbreviations

A	Ampere
ADMD	After Diversity Maximum Demand
AMEU	Association of Municipal Electrical Undertakings
CCT	City of Cape Town
CFLs	Compact Fluorescent Lamps
CPI	Consumer Price Index
CPP	Critical Peak Pricing
DE	Department of Energy
DISCO	Distribution Company
DLG	Department of Local Government
DME	Department of Minerals and Energy
DPE	Department of Public Enterprises
DSM	Demand Side Management
EdF	Electricité de France
EE	Energy Efficiency
EPP	Electricity Pricing Policy
ERS	Electrification and Rural Subsidy
FBE	Free Basic Electricity
HDS	High Demand Season
HV	High Voltage
KSACS	Key Sales and Customer Services
kVA	kilo Volt Ampere
kWh	kilo Watt hour
LDC	Load Duration Curve
LDS	Low Demand Season
LF	Load Factor
LPU	Large Power User
LSM	Living Standards Measure
LV	Low Voltage
MD	Maximum Demand
MFMA	Municipal Finance Management Act
MV	Medium Voltage
MW	Mega Watt

MWh	Mega Watt hour
NAC	Network Asset Charge
NER	National Electricity Regulator
Nersa	National Energy Regulator of South Africa
NMD	Notified Maximum Demand
NRS	National Regulatory Services
OCGT	Open Cycle Gas Turbine
OP	Off-peak
P	Peak
PFMA	Public Finance Management Act
R	Rand
RTP	Real Time Pricing
S	Standard
SPU	Small Power User
STD	Seasonal Time-of-day
TD	Transmission and Distribution
TOD	Time-of-day
TOU	Time of Use
V	Volts
VAT	Value Added Tax
W	Watt
WEPS	Wholesale Electricity Pricing System

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1. Introduction

1.1 Background to the problem

Since the introduction of electricity for industrial and residential use during the 19th century, electricity utilities around the world have grappled with the choice of charging customers for the use of their product at an appropriate tariff.

Electricity was unlike any other product: electricity could not be produced and stored in large volumes for consumption at a later time. Electricity had to be produced in quantities that were actually required by customers at a time when they wanted to use it. These quantities were dependent on the normal cycle of communities. Initially, it was determined by the time the sun set that necessitated evening light. Later, the duration of the normal workday started playing a role as industry used more electricity. As more residential activities could be done using electricity, the time most people got home from work, social habits like the time a community had its meal times or the time when most people went to bed at night, etc. influenced the way electricity was used.

The electricity utility, like most business, had to ensure that whatever it charged its customers, that the income it generated exceeded its expenses in order to remain sustainable. There were day-to-day operating costs like fuel used for generation, wages for staff who had to operate and maintain the system, administration costs and some profit. In addition, there was also a need to have generation plant installed in the first place and reticulation networks had to be built.

Thomas Edison derived the first commercial tariff for electricity in 1882 when the need for electricity was influenced by the successful development of the filament lamp. The cost was simplistic as streetlights had to burn for a set period during the night and hence the consumption could be estimated. A flat rate was thus charged based on expected hours of consumption. It was only in 1896 that Arthur Wright of the Brighton utility successfully metered the first customer when the demand could be determined via the use of an ammeter [Ramokgopa, 2007]. Customers were charged for the demand that they were registering via the Hopkinson tariff where demand was the main criteria for billing. This demand was measured at any time and was not necessarily at the same

time as the system peak. A second part to the Hopkinson tariff was an estimate of the energy that would be used. At the time, this philosophy was suitable as most of the system load was for lighting load which had little diversity amongst customers.

Of course, electricity was being used for more than just lighting as the electrical technology developed. Different industry started to use electricity more until, eventually, lighting was not considered the bulk of the load anymore.

The nature of the electricity demand of an area is that it is rarely consistent throughout the day or year. This consequence is that as generating plants have to match the demand from an area, certain generating plant might only be needed for the peak times that could only last for a few hours per day. Similarly, on an annual basis if demand were related to climatic conditions, e.g. during winter where more space heating could be required, this generating plant might only be used for a few hours of the day and for a few weeks of the year. The rest of the year this generating plant would effectively be idle.

In order to supply the increasing load, more generation plants were being commissioned that were using different types of fuel that all contributed to different specific costs. In addition, these different generation plants had different capital costs, which had to be considered when an electricity rate or tariff was calculated. Certain generating plant was used only for selected times of the year when increased demand had to be supplied. However, the additional generating plant needed to be capitalised, and this capital had to be serviced. This meant that the price of electricity had to cater for plant that was used very selectively. This drove the average price of electricity higher.

There were effectively two choices to cater for peaks that occurred for very short periods of the year, viz. build generating plant that would cater for these times (but would be used sparingly for the rest of the year) or reduce demand during these times. The latter option forms part of the Demand Side Management (DSM) philosophy that proposes to adjust the demand profile rather than build expensive power stations. One type of DSM tool is Time of Use (TOU) tariffs.

In 1958, the first Time of Use (TOU) tariff was implemented in France [Acton et al, 1983] where the different costs of generation could be catered for: electrical energy was

charged a different rate for different times of the day. The more expensive the rate, the more the utility was trying to encourage customers to use less due to supply constraints; conversely, the cheaper the rate, customers were being encouraged to use more electrical energy due to the availability of more excess supply capacity.

Customers could benefit financially if they were able and willing to maximise their electricity usage during the cheaper periods and minimise their use during the expensive periods. The utility benefits as there should then be more of a balance between supply and demand as demand is reduced during expensive periods where supply capacity might be constrained. Secondly, generating plant is used more efficiently when customers opt to use more during the cheaper periods when there might be greater excess capacity.

In addition, seasonal aspects were included that, for example, allowed for higher charges during the colder winter months for the different times of the day where as examples, space and additional water heating put extra strain on the system. Space heating load would not be present during the warmer summer months while smaller temperature differences between ambient temperature and required water temperature required less energy. Hence generating plant that may have been required during winter would not be required as often during the warmer months. During the 1970s and 1980s the USA started experimenting and implementing TOU tariffs not only on industrial and commercial customers, but also on residential customers.

In South Africa, the public utility, Eskom, implemented the first TOU tariffs during the early 1990s for its larger customers. The pricing philosophy was gradually extended to more customers while more municipalities (who are supplied by Eskom and have their own customers) are employing TOU tariffs to charge their customers. The biggest municipality in the Western Region has made time differentiated TOU tariffs available to their customers in 2008 for the first time in its existence.

Eskom's Distribution division is divided into six regions. The author, with the support of Western Region within Eskom Distribution, had access to the region's data that allowed the opportunity to assess the impact of TOU tariffs within Western Region.

1.2 Hypothesis and objectives of this thesis

Based on the preliminary expectation of response to TOU tariffs and the expansion of this type of tariff by other utilities, the hypothesis can be formulated that:

Time of Use tariffs have been effective in the Western Region.

The immediate questions that emanate from the hypothesis include:

1. What are the origins of TOU tariffs and what has the world learnt since its inception?
2. What was the goal of TOU tariffs in South Africa?
3. In order to determine if TOU tariffs were effective, one needs to determine how the results have reflected in relation to its intended goals?
4. How have customers that have been exposed to TOU tariffs responded to the inherent pricing signal?
5. Are the intended goals still appropriate or should a new definition of 'effective' be defined in line with present and future requirements?
6. If effective, could TOU tariffs be extended to more customers in South Africa?
7. Are TOU tariffs the 'be-all' of South Africa's requirements? What other Pricing options are available?

1.3 How can hypothesis be tested?

With the support of Eskom Distribution, Western Region, the author has access to sources of information about selected individual customers' electricity monthly accounts. The information is limited to larger power customers that are supplied by Eskom, Distribution (Western Region) and excludes small and residential energy users. The opportunity allows the investigation of the impact of TOU tariffs on Eskom's customer base to create a better understanding of customer behaviour. These methods might then be applied in a broader South African context. Access to other customer related information that will be described in Chapter 4.

From an ethical perspective, customer details cannot be disclosed. Actual energy and demand readings will be omitted with the focus more on the shape of individual profiles and the use of indexed values.

1.4 Research Scope and Limitations

Eskom Distribution, Western Region's headquarters is based in the Cape Town urban area. The Region stretches as far east as Plettenberg Bay on the South African South Coast, as far as the Namibian border on the South African West Coast, and as far as the Upington supply area in the South African midlands as shown in Figure 1-1.

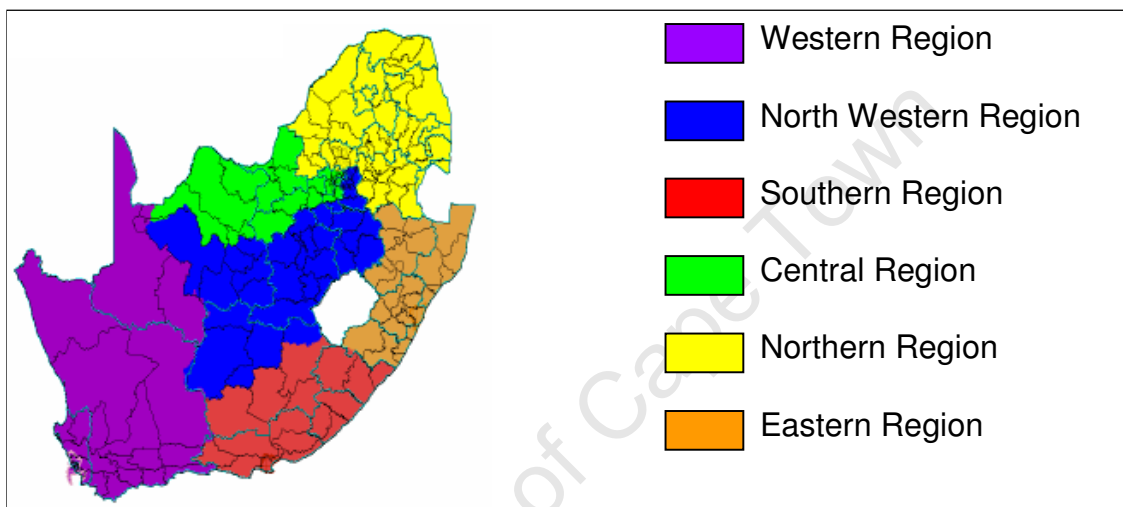


Figure 1-1 Different Eskom Regions within South Africa¹

The overwhelming majority of customers are supplied by either Eskom or a local re-distributor like municipalities. The available data was limited to Eskom customers only.

Eskom classifies customers as Large Power Users when their contracted supply is at least 100kVA. Specialised metering is required that allows for data storage and the utility to remotely download consumption over a set period. The available data related to LPU customers and included full load profile data.

¹ Regional boundaries as per proposed Regional Electricity Distributor boundaries of EDI Holdings [EDI Holdings, 2005]

1.5 Structure of Thesis

Chapter Two will present the literature survey of terminology and concepts mentioned in the hypothesis. When the issues raised in section 1.2 are more internationally orientated, they will be discussed in Chapter Two. Existing sources will be used to shed light on the research questions to gain insight into the topic.

Chapter Three will discuss the origins and development of South Africa's TOU tariffs from the first attempt in 1986 to the latest changes in 2008. When the issues in section 1.2 are more related to South Africa, they will be discussed in Chapter Three. This will include the goals of tariffs in South Africa and how the results have reflected comparatively. An attempt will be made to determine the effectiveness of TOU tariffs from the information presented.

Chapter Four will discuss the methodology that will be followed to analyse the data that includes how customers can be segmented to provide distinct customer groupings.

Chapter Five will include the Preliminary Data Analysis of randomly chosen LPUs. The only selection criteria for these LPUs will be that they should not include municipal supplies, and whether they are supplied from a substation located indoor Medium Voltage (In Western Region this is limited to 11kV, 22kV and 33kV) breaker or stand-alone equipment in the field. Customers will be chosen as far as practically possible on a random basis with very limited criteria to ensure that the customer segmentation is not in any way biased towards a certain preferred result. Customers' responses to seasonal pricing signals will be tested. Examples of the different tariffs will be analysed to determine the most significant aspects of the different tariffs.

After further customer segmentation into specific industry types (from an Eskom perspective), Chapter Six will analyse the different customer groups from a seasonal demand and energy perspective. Chapter Seven will analyse the same customer groups from a daily demand perspective.

Chapter Eight will discuss the findings of Chapters Six and Seven to investigate the different customer groups' response to the different pricing signals of the various TOU tariffs.

Chapter Nine will discuss the outcome of TOU tariffs in the Western Region in relation to the original intentions. Where possible, the implications will be discussed.

Chapter Ten will reflect on the research questions, the validity of the hypothesis and some of the implications of it.

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2. Literature Survey

This chapter explores the questions that emanated from the hypothesis as reported in international, as well as local literature.

However, a better understanding of TOU tariffs is first required to gain insight into some of the discussions. This chapter starts by discussing the fundamentals of TOU tariffs, which will often be related to South Africa to gain greater relevance followed by a literature review of the issues raised in Chapter One.

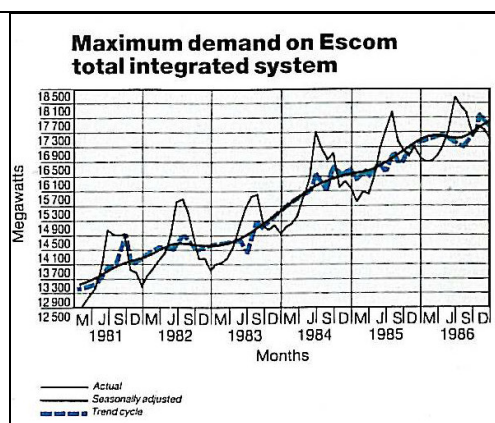
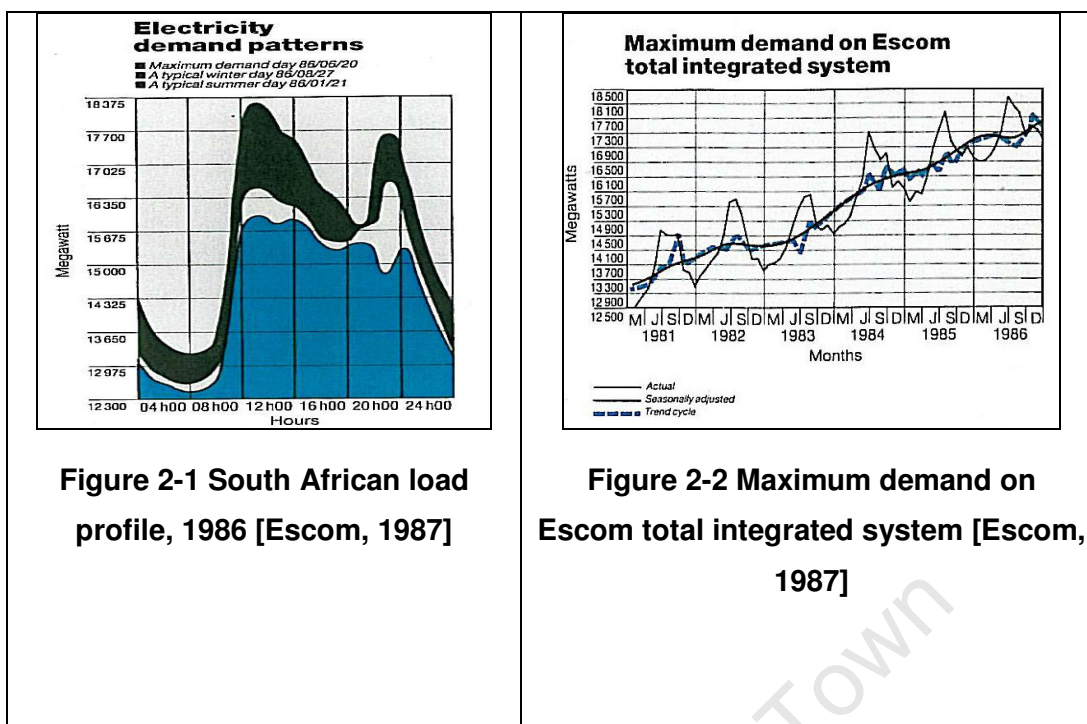
2.1 What are the fundamentals of TOU pricing?

Achieving a balance between supply and demand for more of the time is a task common to most industries but electricity is different. As noted by Kasulis et al. [1981]:

Toys (e.g. Christmas season), air conditioning (during summer season), and lawn care products are examples of industries with seasonal demand cycles that need to be coordinated with supply. Electrical utilities have a more complex problem than most industries. Electricity consumption not only has seasonal cycles, but also time-of-day (TOD) peak and off-peak periods. Further, as electricity cannot be stored for later use, production capacity must correspond to the maximum load demanded, even if that demand is for short periods of time.

As stated in Chapter One, the nature of an area's demand profile is such that it contains peaks and troughs. The peak periods may be for short periods of the day or only a few days or weeks of the year (see Figure 2-1 and Figure 2-2 for South Africa's demand profiles). A utility could either provide more generating plant to cater for those brief peak periods or try to manipulate the demand profile so that the demand during those peak periods is reduced. Providing generating plant is generally considered the more expensive option as stated by Atkinson [1979]: *In an effort to combat escalating operating and capital expenditures in electricity generation, considerable attention has recently been focused on levelling or shifting downward the load curves...* [Atkinson, 1979]

Generally, it is too expensive to cater for the very short peak times and then have under utilised equipment during off peak periods. These expenses eventually



translate to higher average costs for the consumers as the sellers try to recoup the investment in additional assets needed to supply peak demand. The alternative is to reduce the demand.

As stated in Chapter One, electricity costs need to include operating costs as well as an allocation for the capital costs of the plant. Acton et al. [1978] summarised the costs as follows:

Electricity costs depend importantly on the daily and seasonal patterns of demand. Utilities use a variety of generating resources that have different efficiencies in generating electricity. Because of the daily and seasonal variation in electricity demand, less efficient plant must sometimes be called into operation, making the cost of supplying a kilowatt-hour (kwh) vary in accordance with the peak load conditions of the utility. The particular level of cost varies from one utility to another and depends on the generating resources available. The costs range from a fraction of a cent per kwh to several cents per kwh generated, depending on the type of fuel being employed and the nature of the generator (baseload, intermediate, or peaking plan).

The philosophy of using different generating plant is not unique to electricity production. In most business when there is different plant than can be used to produce a product, it makes business sense to use the most efficient plant for most

of the time. When demand for the product becomes more than what that plant can produce, less efficient plant is used to produce that additional quantity despite it costing more to operate.

And further:

Time-of-day and seasonal rates also support the generally accepted principle that electricity rates should be cost-based. Since the operating and capital costs vary with peak load conditions in a utility, a rate structure incorporating this variation will more accurately track costs. Furthermore, it will serve the objective that customers pay in proportion to the cost they impose on the system. [Acton et al., 1978]

TOU (also referred to as 'TOD' in several literature sources like Acton et al. [1978]) tariffs entails charging different energy rates for different times of the day. Typically, the most expensive rate is charged during the system peak times when *less efficient plant could be called into operation* while the least expensive rate is charged during the system off-peak periods when more efficient could be in operation. As stated by Acton et al. [1978], with TOU tariffs *customers pay in proportion to the cost they impose on the system.*

The impact of TOU tariffs would include *levelling or shifting downward the load curves* [Atkinson, 1979] as customers respond to the different rates in a day or year. Some of the benefits ultimately include reduced costs to the end-customer as described by Kasulis et al. [1981]:

Spreading demand load results in lower capital expenditures for the producer and distributor because of reduced capacity requirements, lower operating costs, and benefits to the consumer from the passed-on savings. Moreover, if peak/off-peak users are charged prices related to the costs of serving them, synchronisation efforts will lead to a more efficient allocation of resources.

Higher peak rates tend to encourage customers to move energy use to less expensive non-peak times, thereby increasing the system load factor. This decreases the need for expensive generating plant that is only utilised during short peak periods (in South Africa this is a total of 5 hours per weekday on Eskom's Megaflex, Miniflex and Ruraflex tariffs [Eskom, 2008b]), this decreases the supplier's marginal cost of production which can be eventually be transferred to more affordable per kWh costs to the end customer.

Short run marginal costs reflect the additional cost of meeting an increment of demand in a specific hour assuming the system plant and equipment cannot be altered,

And

Long run marginal cost reflect the additional costs of meeting an increment of demand assuming the system plant and equipment can be changed to re-optimize the system. These costs therefore include capacity/capital costs incurred due to an increment in demand as well as short run marginal costs.

[Calitz et al, 1990]

The long run marginal cost is dependent on initial capital requirements to build the generation unit plus operating costs of producing the next unit of energy. In addition the capital cost of the transmission and distribution network with its operating costs need to be added to complete the broader picture of the costs that contribute to the long run marginal costs.

As an example of the generation component, the capital cost of building a nuclear power plant exceeds the cost for a fossil fuel or coal fired power station (Figure 2-3). However, the operating cost of a nuclear power station is lower than the cost for a coal fired power station.

The short run marginal cost (operating cost) of supply of the Open Cycle Gas Turbine (OCGT) generation units is probably considered the most expensive form of generation available in South Africa with lower capital cost requirements but higher operating costs. OCGT are therefore financially viable if used during peak times only.

These economic facts probably contribute to the size of the different sources of generation in South Africa. Eskom has completed and is busy constructing different types of generation power stations. The proposed Medupi coal fired power station will be a 4200MW base load station while an OCGT power stations like Ankerlig (4 x 150MW) and Gourikwa (3 x 150MW) contribute 1050MW. The OCGT power stations are envisaged to operate during peak hours only but provision has been made for the units to run up to 8 hours per day [Eskom, 2009].

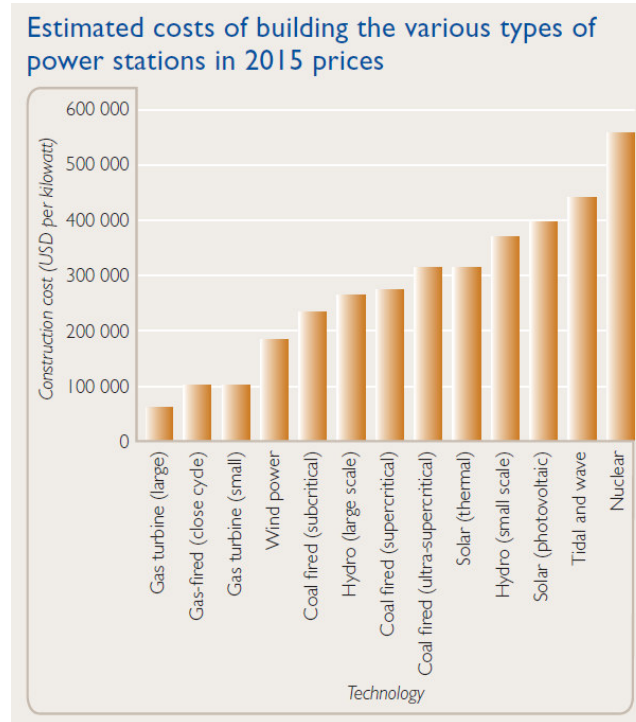


Figure 2-3 Estimated Costs of building the various types of power stations in 2015 prices [Eskom, 2009c]

Ideally, the units that are the cheapest to run (operating cost) should be used the most – base stations like coal or nuclear; conversely, the units that are the most expensive to run, should only be used selectively, like peak times or emergency situations – peaking stations like OCGT.

... *they* (TOU tariffs) *are designed to reflect the prices under expected, long-run conditions*; [Faruqui et al, 2002]

Hence, TOU tariffs are an indication of the expected long run marginal cost of supply.

In South Africa, there are broadly two markets operating in the country, viz. the Wholesale market or based on the Wholesale Electricity Pricing System (WEPS) and the Retail market that uses a range of tariffs. The Wholesale market is used by utilities (or large enough customers) to purchase energy from the South African Power Pool (representing Generation sources) while the Retail market is used by the same utilities to sell directly to their end-use customers. In South Africa, the wholesale market was made available to customers who met the qualifying criteria [Eskom, 2007a]:

- *minimum electricity consumption of 100 GWh in any 12 consecutive months*
- *situated on contiguous sites ('contiguous' means adjacent to or touching)*

- *managed under a common management structure*

WEPS is designed as a cost-reflective tariff to recover the cost of energy (generation), network services (transmission) and other costs necessary to deliver a wholesale electricity service. This will include costs for losses and wheeling through the distribution system. These costs will be unbundled to show the customer exactly what is paid for. Provision is made for levies and taxes that support socio-economic programmes. [Eskom, 2007a]

The cost of energy is based on a TOU system that is differentiated by time of day and the particular season. For any utility to remain sustainable the costs incurred (from purchasing via WEPS) must be less than revenue generated from the Retail tariffs. Hence the package of retail tariffs that a qualifying utility may use is ultimately based on the WEPS tariff but much simplified.

2.2 What are the origins of TOU tariffs and what has been learnt

TOU tariffs for electricity are not a new phenomenon. TOU tariffs were introduced in France in 1958 as the *Green Tariff* [Acton et al, 1983] after marginal cost analysis in 1955 by EdF². Participation was at first voluntary for high voltage customers but 10 years later it was mandatory for all high voltage customers. TOU was first introduced to residential customers in France in 1965 [Charles River Associates, 2005].

Gradually, more European countries participated after the success of the French. The USA started considering TOU tariffs in the 1970's based largely on the success in Western European countries [Acton et al, 1983].

As TOU tariffs were in its relative infancy, several countries initiated pilot programmes or experiments to gain greater understanding of the TOU tariffs including its impact on the customer and the utility.

Vickrey [1971] stated that *prices of perishable commodities vary from time to time with considerable suddenness in such a way as to keep supply and demand in*

² Electricité de France

balance, rationing the more limited supplies to the more urgent needs and assuring full utilization of supplies when they are relatively plentiful.

While other *commodities* are allowed to have variable prices, electricity prices are often expected to remain static; Vickrey states that this leads to a *great deal of waste in the utilization of the relative inflexible facilities characteristic of most utilities.*

Some of Vickrey [1971] findings include:

- *Utility prices that are made to respond appropriately to adventitious variations in demand or supply can produce substantial improvement in the efficiency of utilization of utility facilities, raising load factors and lowering average costs.*
- Where short term price fluctuations are shared with customers, they are often not allowed to be shared with all customers. This leads to cross-subsidisation and a *perverse* [Vickrey, 1971] situation where the customers that use most of their energy during peak times are subsidised.
- Prices should be set at short run marginal costs.
- *The main difficulty with responsive pricing is ... political.*

Wenders [et al, 1976] indicated that one of the main obstacles to *peak-load pricing* is the cost of metering for small and residential customers. He emphasised that this is not the case for larger customers. Wenders further stated that the results of a six year experiment undertaken by the *Electricity Council in London* found that a residential *Seasonal time-of-day (STD) tariff* led to an improved load factor, although *the results suggest a greater filling of valleys than shaving of peaks.* He concluded that residential customers do respond to STD but that a straight seasonal tariff would be the best alternative in the long run.

According to Acton [et al, 1980], the response to TOU pricing is greatest under the following conditions:

1. When customers have electric-intensive loads.
2. When part of load is discretionary.
3. When excess production capacity allows concentrating activities and off-peak periods.
4. When cogeneration is available.

It was found that households with more appliances are more demand responsive to price changes than those who were not as materially fortunate [Granger et al, 1979; Lillard et al, 1981].

Lillard [et al, 1981] other conclusions include:

- Price elasticity is not simply a factor of relative price change. If that demand were due to climatic conditions (air conditioner in hot weather or space heating during colder winter months) the demand response is also impacted by the extremity of the weather. If too hot, price responsiveness might be less as the inconvenience might be greater compared to a mild day.
- Other factors that affect responsiveness include *permanent consumption level, house characteristics and family characteristics*.
- TOU, *if based on marginal costs, will be potentially superior* (to flat tariffs).

Acton [et al, 1981] made the following telling statement with regards to specifically industrial and commercial TOU programmes:

The empirical evidence from 20 years of European experience with TOU rates have been encouraging. Although the response of firms has varied widely even within a single industry, the same conclusion emerged from every empirical study: TOU rates change load curves by reducing peak loads, increasing off-peak loads, or causing loads to shift from peak periods to shoulder and off-peak periods.

Hausman [et al, 1984] surmised for a residential TOU programme in Canada that displayed an annual winter peak:

- The longer *Time-of-Day* (TOD) tariffs were in place, the greater the response from the customer as they experiment, learn and adapt to the tariffs.
- Compared to the control group, residential TOD customers' annual electricity bill was 43% less and that they paid on average 66% less per kWh.
- The response during winter was greater than during summer for his experiment. He stated that this was due to the availability of alternative fuel sources to generate space heating (wood, gas) while similar alternatives were not easily available for space cooling with respect to air conditioning load during summer.

However, the TOD customers were voluntary participants and already had an awareness of the benefits of TOD tariffs. The same levels of response should not be expected if TOD tariffs were implemented for all residential customers.

A study of five utilities' experimental residential TOU programmes in the US by Caves [et al, 1984] was initiated and revealed the following general patterns with a summer peak:

- *The substitution elasticity is greater for customers with more appliances.*
- *The substitution elasticity is greater in warmer climates (referring to residential air conditioning).*
- *There is an interaction between appliance ownership and climatic effects. The climate effect is larger in the presence of all appliances and appliance effect is larger in warm climates.*

A study by Park [et al, 1984] for several thousand large industrial and commercial customers of ten US utilities show:

- *There is in fact a small but highly significant reduction in the fraction of electricity that large customers consume on peak when time-of-day prices are introduced.*
- *The average response differs substantially from industry to industry.*
- *The magnitude of the reduction is significantly related to peak-period price differentials.*
- *Energy (kWh) price differentials and peak demand (kW) prices appear to be about equally effective in reducing peak demand.*
- *Other factors, including the length of the peak period, customer size, and weather, significantly affect response to time-of-day rates.*

Aigner [et al, 1985] indicated that *if time-of-use price ratios are large enough, customers will respond*. The response for non-residential customer would not be limited to simply reducing demand but the use of alternative sources of energy.

Is the peak problem being addressed or is it merely being shifted to another time period? Theoretically, if all customers were on a TOU tariff, and gradually moved their demand from the Peak times to say, the Standard time, the problem would theoretically then have moved to Standard time.

TOU tariffs have been in place in France since 1958 and it is still operational today. The structure may have changed over the years to cater for the changing environment. However, TOU tariffs are still in place, five decades later while

statistically customers do not respond beyond a desired level. The desired response is dependent on the price differential between the peak and non-peak periods [Park et al, 1984; Aigner et al, 1985]. Therefore, it does not appear that the maximum demand simply moved from the Peak time to the Standard time.

When customers reduce demand during peak periods, it is not certain how they will return to normal demand after the peak periods. Caves [et al, 1987] indicated that *time-of-use pricing does not lead to problems of needle peaking just outside the peak pricing period*. He found that there was a greater response from customers when moving from off-peak to peak periods as opposed to the comeback load after the peak period. This fact was later also noted by Train [et al, 1994] after a survey of TOU programmes.

Thus far, most of the programmes that were reported included experiments or pilot programmes that were not considered permanent. After a study of a permanent programme, Taylor [et al, 1990] made the following assertions:

- *...customer response increases over time in a manner that enhances the ability of TOU rates to reduce system peak.*
- TOU tariffs promote efficiency of electric plants and *slow the need for additional capacity*. Note, there is still an ultimate need for additional capacity; TOU only delays the need for immediate additional capacity.
- *In addition to adjustments that shift consumption from peak to off-peak hours, households may also make changes that reduce consumption during all hours.*
- The inclusion of a demand charge leads to improved load factors as customers are now aware of creating *needle peaks*.

Train [et al, 1994] stated that a survey of TOU programmes revealed that voluntary residential TOU programmes were *far more prevalent* while mandatory programmes were *more common* for the commercial and industrial sectors.

Seeto [et al, 1997] argued that *for most regulated DISCOs the modern Hopkinson tariff with demand subscriptions will be superior to TOU rates, as it can better handle the load diversity of local transmission and distribution (TD) demands made on the contemporary DISCO*. (The simplest form a Hopkinson tariff refers to a rate that includes an energy charge per kWh with a demand charge per kW of demand.) He

was referring to independent distribution companies (DISCOs) that were not part of a vertically integrated utility that included generation. He justified his argument by indicating the TOU energy rates are based on generation's marginal cost while not accounting for TD's challenges.

Seeto [et al, 1997] warned that alternative sources of energy or on-site generation could have a long term unwanted impact. He noted that customers consider alternative energy sources *that will satisfy its needs at lower costs than would be incurred when paying the DISCO's prices*. The alternative becomes a permanent fixture that results in loss of income to the utility. The knock-on effect means that the utility now has to recoup costs from a smaller *customer base and an immediate loss of revenue* resulting in *higher rates to other customers*. This could exacerbate the issue with even more customers considering alternative energy sources.

Kirschen [2003] stated that without TOU tariffs and only flat tariffs being available, the customer's *cycle of activities* will determine their consumption profile. He also indicated that when *electricity energy costs make up a small portion of the total costs of producing industrial goods*, customer response to changing electricity prices will be *relatively small*. *Similarly, most residential customers will probably not reduce their comfort and convenience to cut their electricity bill by a few percent*.

TOU tariffs can benefit customers who are prepared to favour the less expensive periods to the more expensive periods with respect to energy use. When there are additional factors like strained resources and an unfavourable economic environment the financial benefit for the additional customer could become more attractive as illustrated by:

Since the oil embargo of 1973, and more recently with the introduction of competitive markets, large power users in many countries have bought their power at a TOU rate. Even residential and small commercial customers are now being offered this option as a way of lowering their bills. [Faruqui et al, 2005]

The above paragraph illustrates that all types of customers of all sizes could potentially be exposed to a TOU tariff to gain access to the financial benefit of a reduced bill.

2.3 Other Pricing Options

Other than TOU tariffs, other types of tariffs are available but would have different impacts on both the customer and utility. Pricing options could present some risk to the customer but they are marketed with the promise of a lower average price (see Figure 2-4). It is evident that the smaller the risk to the customer the greater the risk to the utility.

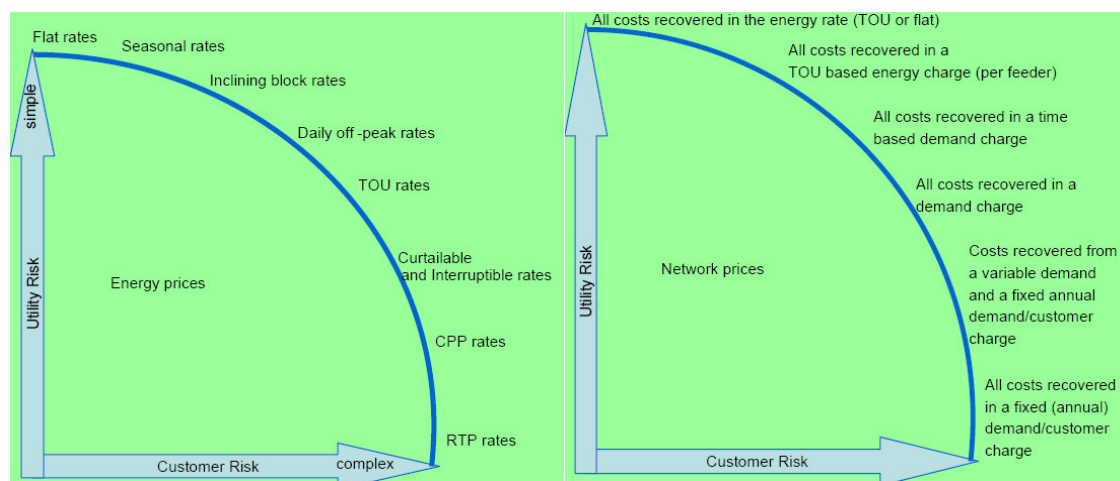


Figure 2-4 Risk chart for the different pricing options [Charles River Associates, 2005]

In a perfect 'tariff world' there is a direct relationship between the retail customer and the retail utility, and between the retail and wholesale market. In this world the wholesale tariff is set that aims to be a reflection of the generation mix, which ultimately determines the retail tariff. The retail tariff elicits a response from the retail customer. This response is noted by the retail market utility (that set the retail tariff) and is communicated to the wholesale market utilities. They then adjust their tariffs and the cycle starts again. This cycle repeats itself on an ongoing basis until an equilibrium point is reached where wholesale and retail tariffs are a reflection of the 'perfect balance' between the generation mix and the customer response.

A brief discussion will follow about different types of pricing options that could be used. It does not mean that these are the only options available but simply a brief illustration of the dynamics of other tariff options.

2.3.1 Real Time Pricing

The more volatile the price is likely to be, the lower the average price promised. Therefore, Real Time Pricing (RTP) would have the lowest average price. However,

the risk is that there will be times when the customer will not know what the price will be. The utility shares some of the risk with those customers who do participate.

RTP is considered high risk, especially with low supply reserve margins. Low reserve margins lead to price volatility as unplanned supply side outages will lead to demand exceeding supply situation which will theoretically push the price up until demand balances supply. Calitz [et al, 1990] indicated that RTP is a good concept when there is a considerable supply surplus. However, when reserve margins become constrained, RTP means exposure to volatile prices.

Customers can ensure some protection against excessive prices for unsustainable periods. As an example, customers can enter into hedging agreements with the utility to ensure that the price paid does not become (theoretically) 'excessively high'. As some of the risk is now being limited, the average price would increase compared to complete exposure to RTP.

However, a Retail RTP market needs to be balanced with a similarly structured Wholesale RTP. If price 'caps' are to be introduced via regulation to the Retail market as protection against excessively high prices, that same protection is necessary for the Wholesale market. If this is not done, the Californian scenario could surface where the utilities were effectively exposed to excessive prices for prolonged periods while the retail market was protected with price caps. With a legal obligation to supply customers, the utilities were forced to sell at a loss for an unsustainable period that eventually led to unsustainable financial burdens to the utility.

RTP is already being offered to very large customers in South Africa while Faruqui [2007] has already noted some success with the local program. He further states that *...customer response is not used to optimize the dispatch of the power system. Electricity prices are based on the Pool Output Price, and do not change in response to changes in customer demand that may be induced by RTP. The utility is not aggressively marketing the program for this reason.*

2.3.2 Flat rate

On the other end of the pricing options scale, a flat energy tariff for the year with no variability will be found. No matter what the network condition the price will remain the same as is generally the case with the South African residential customers. The

utility carries all the risk as it pays a price that is effectively a RTP that is inherently volatile. The price paid by the customer should theoretically be the highest average price of all the pricing options as there is no risk to the customer.

2.3.3 TOU

In the middle of the scale, there is the standard TOU tariff. As already ascertained, in South Africa it comes in many guises but common to most is the three time periods during the day that are charged at different rates. In addition, there is the addition of a different set of daily values for the two different seasons [Eskom, 2008c]. Prices for the different times of the day are known beforehand and are fixed for the duration of period that the tariff has been approved. As there is relatively no risk associated with the standard TOU tariff to the customer, the average price will be greater than for RTP [Charles River Associates, 2005]. TOU rates are a reflection of the average long run marginal costs for the different times of the day and different seasons. Therefore, the utility can share some of its risk associated with long run marginal cost with the customer, albeit at an average rate. Note, there is no facility in TOU tariffs to cater for short run marginal costs that are inherent to the price the utility pays. The utility thus carries the risk of short run marginal costs while the long run marginal costs are effectively shared with the TOU customer.

2.3.4 TOU + CPP

Considered somewhat of a compromise between RTP and TOU, is TOU + CPP (Critical Peak Pricing). The TOU tariff is in place for most of the year. For typically 12-15 days of the year [Faruqui, 2007], depending on the utility, and for a limited amount of time, a CPP rate will apply. The rate will be known before hand but the time of implementation will not be known. Customer notification could happen the day before, a few hours prior or even 1 hour prior to the implementation of the CPP. Typically, the utility will use CPP when there are extreme shortages on the supply side due to unplanned maintenance.

A South African government Gazette No. 31741 [DME, 2008a] appears to support TOU + CPP with the following Policy position on electricity pricing:

Policy Position: 32

TOU tariff energy charges must be differentiated by:

- *All the components as reflected by the WEPS (Wholesale Electricity Pricing System).*
- *In addition an approved super peak rate to reflect the short term costs could be applied during emergencies in which case customers need to be informed in advance,*

Faruqui [2007] noted that from a survey of *numerous pricing designs for improving economic efficiency* that TOU + CPP (with enabling technologies) for residential customers produces more than double the elasticity values compared to TOU. In his survey enabling technology referred to an automated system that reduces load when a CPP signal is received. The load is reduced by adjusting the air conditioner temperature, or water heating system threshold temperature.

Load shedding is normally applied in South Africa during extreme supply side conditions when unplanned supply side maintenance is required. CPP will cater, to some extent, to curb the retail customer consumption while providing some 'leverage' for the Distribution utility. CPP has the potential to minimise the demand when customers respond to the higher price by reducing their demand and thereby reduce the need for wide scale load shedding.

When there is a lack of sufficient base load power stations energy efficiency and energy conservation are considered short term solutions. An additional CPP component could minimise the need for base load power stations as load shedding only occurs when multiple supply side losses occur.

2.3.5 Curtailable and Interruptible rates

Interruptible rate would apply when customers agree to be disconnected from the system when supply side constraints are in effect. This rate would be especially useful to the utility for customers who are not price responsive, either by will or by nature of their processes.

Curtailable rates mean that customers would be paid for every MWh that is not consumed when requested by the utility [Charles River Associates, 2005]. This is also known as Demand Response. There is the added option of a financial penalty when the customer chooses not to respond. As the customer shoulders considerable risk the average price paid would tend to be lower as opposed to the other options.

Like CPP, there would be a pre-arranged agreement as to the frequency, duration and respective rates to curtail or penalise [Charles River Associates, 2005].

Customers with self-generation would be more likely to opt for this option as there would be less disruption to their business and they can effectively sell their generation capacity to the utility. If the cost of running the generator is less than the financial incentive the customer benefits from gaining financially more from his investment.

When the customer does respond the utility gains as capacity is made available to supply other loads. If the customer does not respond the penalty compensates the utility – at least partially - for the additional short run marginal costs.

2.3.6 Inclining and Declining Block rates

Inclining block rates charges customers more per unit of energy the more they use. Therefore, the first, say, 500kWh could cost x c/kWh, while the next 500kWh could cost $(x+50\%)$ c/kWh and any more energy could cost $(x+100\%)$ c/kWh. The customer faces no risk as all prices are predetermined.

Some long run marginal costing could be included in the determination of the inclining block rates but there is no facility for the volatility associated with short run marginal costs. The customer might become more energy efficient as his consumption increases (due to increased costs) but might introduce low LF patterns in the cheaper blocks that could coincide with system daily peaks. An inclining block rate has been approved for Eskom's residential customers as part of the tariff approval in 2010 [Nersa, 2010].

Declining Block rates is effectively the opposite of Inclining Block rates. The first 500kWh could cost x c/kWh, while the next 500kWh could cost $(x-25\%)$ c/kWh and any more energy could cost $(x-50\%)$ c/kWh. This option does penalise the lower end users and in South Africa this means that poorer users pay more for the first block of energy than wealthier users who would inevitably pay for the cheaper blocks. Politically, this would be the most difficult option to market to all the stakeholders. Again, there is no facility for the volatility associated with short run marginal costs. However, as the customer's consumption increases, low LF patterns could be introduced.

2.3.7 Demand Charges

All the options listed above are effectively energy related charges. The pricing signal is aimed at reducing the total energy consumed over a period of time. However, for customer with low LF, energy costs might illicit less of a response as opposed to demand charges. Demand charges is generally part of most energy related tariffs in South Africa, especially larger LPUs and is typically charged during system Standard and Peak times. Some tariffs do charge a demand charge no matter when it is measured. One of Eskom's strategically identified pricing goals is:

Where practical Eskom tariffs will contain both a load shifting (energy) and load reduction (capacity) signal. [Eskom, 2007]

2.4 What could happen after TOU pricing?

TOU pricing is a form of averaged marginal cost of supply pricing. In countries where TOU pricing is well established, like many first world countries, this tariff is seen as the most basic of pricing options.

TOU pricing is considered the norm for residential customers in countries like France. They have the added element of Critical Peak Pricing (CPP) where even residential customers are charged a considerably higher rate (than highest Peak period) when there is an abnormal unplanned system capacity problem. CPP would require some form of communication from the utility to the end customer. Therefore during normal conditions there are the 3 TOU periods but for a limited amount of time for the year, there will be a CPP period when the system is experiencing abnormal stress.

As an added factor for pricing consideration, the level of reliability could be built into the tariffs. The higher the reliability, the more expensive the tariff is likely to be. A highly reliable supply will be available at a premium.

Ideally, customers would pay the marginal cost of supply for every hour of the day. This is often referred to as Real Time Pricing (RTP). This is already in place for especially larger non-residential customers in several First World countries. In South Africa, there are selected large customers that are already on a form of RTP [Faruqui, 2007].

2.5 Chapter Summary

The chapter summary will indicate if answers to the questions posed in section 1.2 have been adequately answered. The literature survey has provided the following answers to question 1:

- TOU tariffs should ideally be a reflection of the long run marginal cost of generation.
- TOU tariffs have been used to improve load factor and change the shape of demand profiles.
- Customers that have been exposed to TOU tariffs do respond to tariffs.
- Peak-period price differentials influence the level of demand reduction significantly.
- However, the characteristics of a customer's response are not only based on the price differentials within TOU tariffs. Factors like climate, period that tariffs have been in place, appliance ownership etc. affect the way a customer responds.
- TOU tariffs may indirectly lead to greater energy conservation due to increased awareness of electricity consumption.

Question 1 appears to have been adequately answered.

Questions 2 through 5 of section 1.2 will be addressed in Chapter 3 as they are more of a South African nature.

It would appear that the answer to question 6 is that all customers could benefit from TOU tariffs. However, the South African environment and its challenges need to be assessed to ascertain the relevance of this statement.

In response to question 7:

- TOU tariffs can reduce demand during peak periods but might not be able to cater for ad hoc contingencies that occur outside peak periods.
- Other pricing options have been explored. It appears that TOU tariffs should be considered the trigger for more dynamic tariffs that would be able to cater for most requirements.

The suitability of the other dynamic pricing options needs to be discussed in light of the South African requirements that first need to be assessed.

3. The South African Tariff perspective

Chapter Three will discuss the origins and development of South Africa's TOU tariffs, and of tariffs in general, from the early 1980's to the latest changes 30 years later. These will continuously be compared to the shape of the national profile to determine any correlation. When the issues raised in Chapter One are more related to South Africa, they will be discussed in Chapter Three to emphasise the South African perspective. This will include the goals of tariffs in South Africa and how the results have reflected comparatively. The effectiveness of TOU tariffs will then be discussed from the information presented to determine if any further study is required.

In order to understand the present tariff situation within South Africa, it is important to understand the tariff history to gain greater perspective of the present range of tariffs.

One could go back more than 100 years into history but this brief summary of history will only look as far as the early 1980's as this should give sufficient background to the present tariff situation. However, first it is necessary to distinguish between small and large power users in terms of Eskom tariffs at present. Small Power Users (SPUs) are charged a fixed per unit energy cost with no demand charge while Large Power Users (LPUs) could be charged a flexible time differentiated energy cost plus a possible demand charge.

A customer's contracted notified maximum demand or contracted capacity must be at least 100kVA to be considered as an LPU. The contracted notified maximum demand for SPUs does not exceed 100kVA. The metering employed by Eskom for SPUs requires on-site meter reading to determine the overall consumption for the billing period; LPUs, on the other hand, have a comparatively sophisticated metering unit that records when energy is consumed and can be downloaded remotely.

The total energy consumption for individual SPUs for the meter reading period is known but it is not possible to determine a month-long energy profile as there is no time stamp for the energy usage. SPUs' -this includes residential customers - individual customer energy profiles are thus considered relatively unknown. Individual LPUs will have time stamped energy usage records that would make energy and demand profiles relatively simplistic to compile. In addition, summarised monthly billing information is sometimes available for up to ten years for certain LPUs.

The availability of several sources of detailed historical and present usage data makes LPUs ideal to study. In addition, LPUs are exposed to TOU tariffs while SPUs are not. Therefore, the history of tariffs that will be related in this chapter will pertain to LPUs.

3.1 The early 1980's

The Electricity Supply Commission, variously abbreviated as ESC and Eskom, was established in 1923 by the Governor-General *under the powers vested in him by Section One of the Electricity Act, 1922 (Act 42 of 1922)* [Ramokgopa, 2007]. This utility was superseded by a reconstituted Eskom in 1987 by the Electricity Act of 1987 (Act 41) and the Eskom Act of 1987 (Act 40). For convenience, one term, Eskom, is used to refer to both forms of the utility.

In the early 1980's, there were essentially four Eskom tariffs available, viz. Tariff A, B, C and D. Tariffs B,C & D were essentially for Small Power Users (SPUs) and accounted for more than 90% of Eskom's total customers but contributed less than 9% of total revenue. [Ramokgopa, 2007]

Ramokgopa further states that Tariff A was used for larger customers and *applicable to customers with load greater than 25k or kVA*. The two more important elements of this tariff were a demand and an energy charge with the demand charge measured across the whole day. This tariff was based on the Hopkinson tariff that has already been mentioned in Chapters One and Two. The costs were first divided equally; however, the "50/50" rule was altered in 1986 after an empirical derivation showed that at an Eskom level the rates of standard tariff A should be set in such a way that the energy rate was 40% and the demand rate was 60% of the tariff for a unity power and unity load factor customer [Ramokgopa, 2007].

Energy costs were allocated to redeem *running costs* while demand charges were to redeem *standing costs*. Running costs would consist of the cost of fuel and water consumed by the generating stations and expenses to supply the customer while standing costs or *fixed costs are largely dependant on the cost of the necessary generation, transmission and distribution equipment* [Ramokgopa, 2007].

During the early 1980's the South African load profile had the following characteristics:

- Demand peaked at either 09h00 or 11h00 for annual peak day. See Table 3-1.
- Summer demand profile had a morning peak with a lower evening peak. See Figure 3-1.
- Annual seasonal demand peak during southern hemisphere winter during June, July or August. See Figure 3-2.
- Annual seasonal energy peak sales during winter during June, July or August. See Figure 3-3.

	1981	1982	1983	1984	1985	1986
Maximum Simultaneous one-hour demand on total	09h00, 12 June 1981	09h00, 2 July 1982	09h00, 10 August 1983	11h00, 15 June 1984	09h00, 12 July 1985	09h00, 20 June 1986

Table 3-1 South African load peaks, 1981-1986

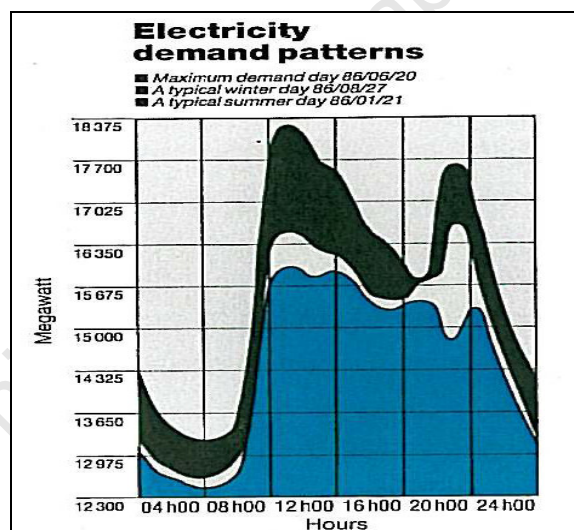


Figure 3-1 South African load profile, 1986 [Escom, 1987]

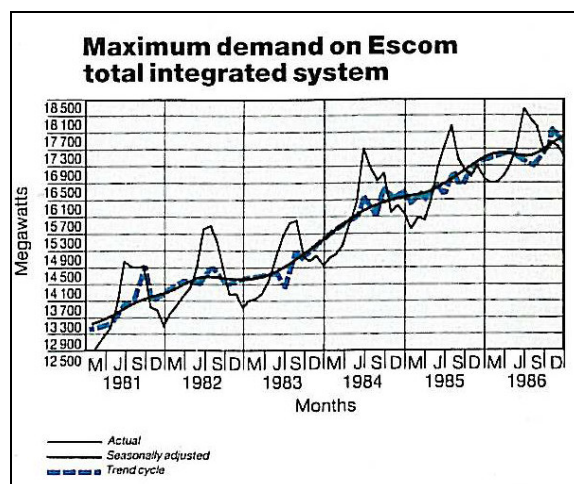


Figure 3-2 Maximum demand on Escom total integrated system [Escom, 1987]

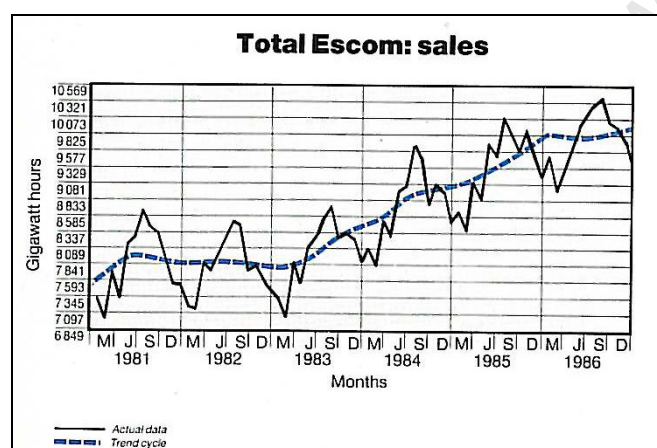


Figure 3-3 Total Escom: sales [Escom, 1987]

3.2 The late 1980's

Another TOU tariff, Tariff E, followed:

Tariff E was introduced during January 1986 as a response to repeated recommendations in favour of an off-peak tariff by inter alia AMEU, the De Villiers Commission... [Calitz, 1989]

Tariff E was similar to Tariff A but maximum demand charges were measured for maximum demands during peak periods only and the tariff was aimed at large power users. The system's peak hours were deemed from 07h00 until 23h00. LPU's could benefit from this tariff if they were prepared to shift their MD for the day to the system's off-peak hours.

In July 1987, Tariff F was introduced and was very similar to Tariff A but was aimed at rural variable supplies with a low load factor and high maximum demand [Ramkogoba, 2007]. As will be shown in later chapters, rural agricultural supplies' load is largely seasonal and crop type related; it will then be shown how these factors lead to a low annual load factor (LF).

As illustrated in

Figure 3-4 and

Figure 3-5, the overall shape of the daily and annual profiles had not changed significantly between 1986 and 1989 after the introduction of Tariff E and F.

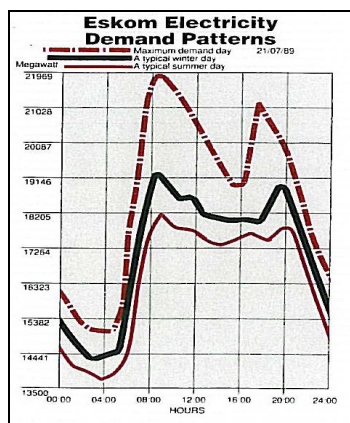


Figure 3-4 Eskom Electricity Demand Patterns [Eskom, 1990]

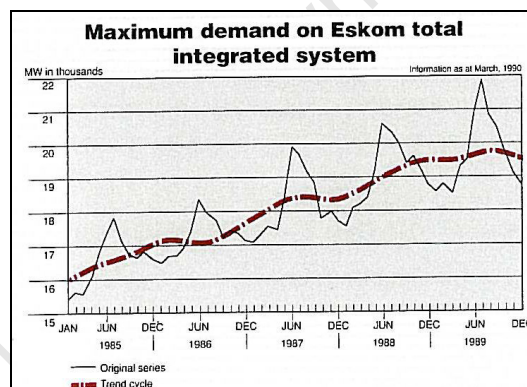


Figure 3-5 Maximum demand on Eskom total integrated system [Eskom, 1990]

3.3 The 1990's

The then Eskom Distribution Pricing manager, Andres Calitz, made the following observations:

In general, it is thought that Eskom system load factors will decline unless active DSM shifting and peak dipping measures are introduced to counter national trends.

And

TOU pricing is the most effective DSM tool to achieve load shifting by customers, and to convey to customers the time-varying nature of Eskom's cost of electricity supply.

[Calitz, 1989]

And

The prime motive for this new tariff proposal is that present tariffs for large customers (Tariffs A, E and F) are outmoded and fail to accurately track the true cost of supply.
[Calitz et al, 1990]

The first two statements above indicated a perceived need to improve the system LF by means of TOU pricing. Calitz indicated that the LF should be improved as *Eskom can reduce its installed generating capacity and increase the share of base load plant in its generating plant mix if daily, weekly and annual load factors can be improved* [Calitz, 1989].

Tariffs A, E and F had an incentive for customers to maximise usage outside peak periods by not charging for demand during non-peak periods. However, as indicated by Calitz [et al, 1990] above, some greater accuracy in terms of selectivity or discrimination was required.

Time of Use (TOU) tariffs were introduced by Eskom in 1991, viz T1 and T2. Tariff T1 was for supplies greater or equal to 1MVA with a demand charge, while tariff T2 was for customers between 100kVA and 5MVA but did not have a demand charge.

Characteristics of the 1992 demand profile:

- The system had moved from a morning peak to an evening peak but still in winter while the summer profile still showed a morning peak. See Figure 3-6.

Tariff T2 was also used by rural customers but due to associated higher losses a third tariff was introduced in 1994. Ruraflex 1 and 2 were introduced for $\leq 50\text{kVA}$ and $> 50\text{kVA}$ respectively.

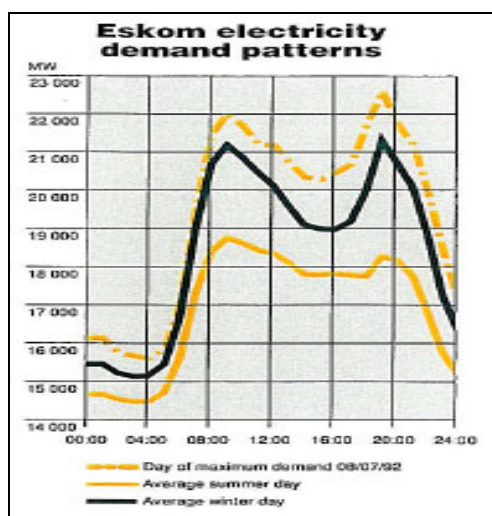


Figure 3-6 Eskom electricity demand patters [Eskom, 1993]

Name changes in 1994-5 led to the following proposals:

After internal lobbying and market research, the names were changed to Standardrate (tariff A/F), Nightsave (tariff E), Maxiflex (tariff T1), Miniflex (tariff T2), Ruraflex (no change), Businessrate (tariff B), Landrate (tariff D), Homepower (tariff C) and Homelight (tariff S). Maxiflex was changed to Megaflex in 1995 because Maxiflex was already a registered brand name of another company. [Ramkogoba, 2007]

And further:

From 1 January 2000, Standardrate and Nightsave were merged into a single tariff called Nightsave [Ramkogoba, 2007]. Standard and Nightsave had similar structures with the main difference being that Nightsave's demand charge was only applicable during the tariff's Peak periods while the Standard tariff's demand charge was measured for the whole billing period.

Nightsave, as mentioned earlier about Tariff E, had a demand charge during the Peak periods only plus an energy charge. However, peak hours stretched from 06h00 to 22h00 on weekdays. Weekends were considered off-peak hours.

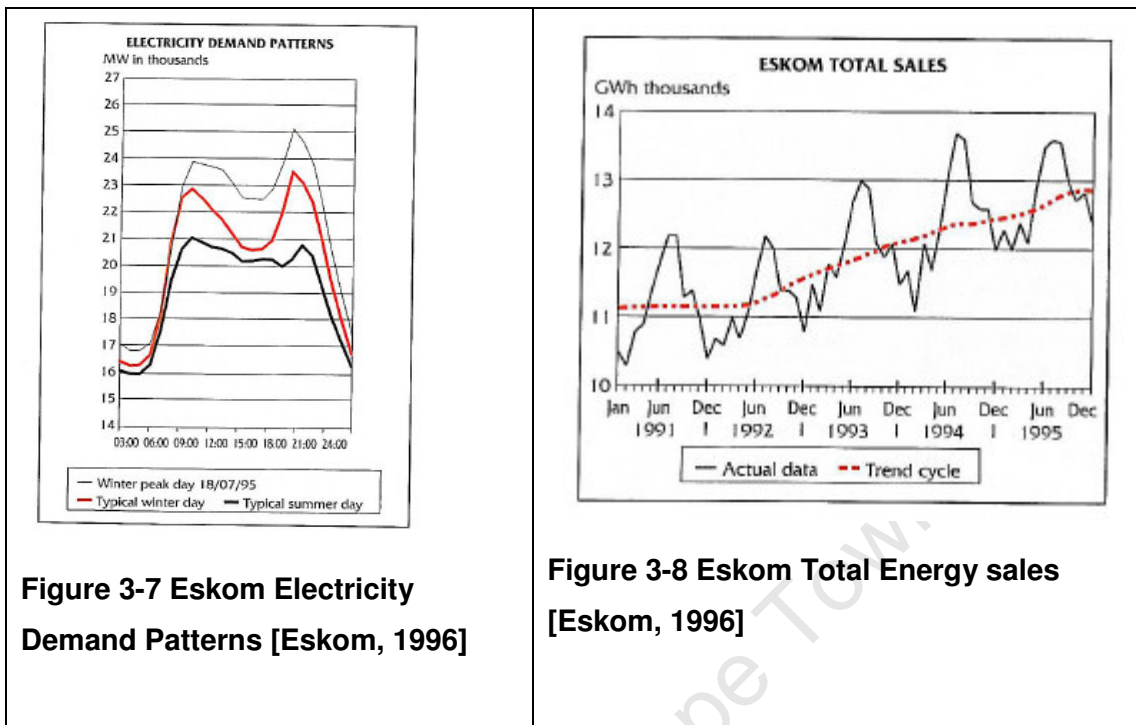
The two main components of Megaflex was a time of day and seasonally differentiated energy charge plus a seasonally differentiated demand charge applicable only for the Standard and Peak periods.

Miniflex and Ruraflex also had time and seasonally differentiated energy charges but had no demand charge.

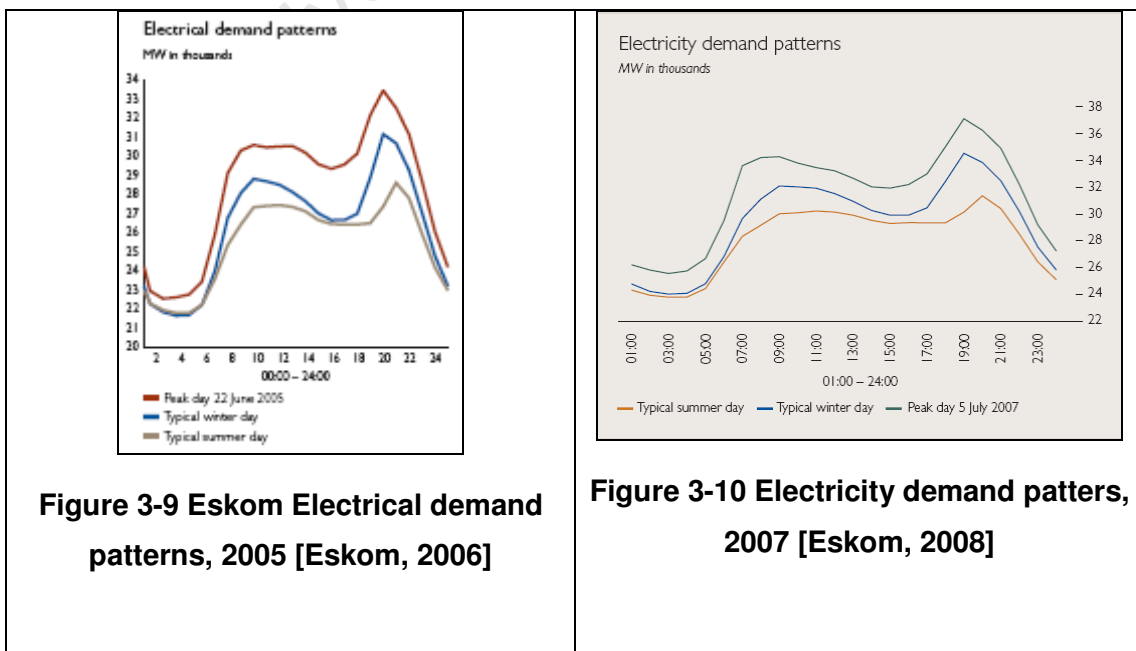
On 1 April 1995 the Electricity Control Board was replaced by the National Electricity Regulator (NER), which had as one of its regulatory areas, amongst others, pricing and tariffs.

It is evident from Figure 3-7 and Figure 3-8 that between 1992 and 1995 that the positions (with reference to time of day) of the daily peaks during the morning and evening appear to have remained consistent. However, the morning peak appears to have been 'flattened' in relation to the evening peak which suggests a favourable response from customers exposed to TOU tariffs. However, there is also the probability that the evening peak could have increased in relation to the morning peak.

Even though the seasonally differentiated energy tariffs were already in place since 1991, the energy sales profile still had a definite winter peak, unchanged since 1986.



When one considers the Typical winter day profiles for 2005 (Figure 3-9) and 2007 (Figure 3-10), the same pattern is still evident. The system still had an evening peak in winter. However, summer months now had an evening peak as well. Again, there is a probability that the morning peak could have flattened (relative to the evening peak), while there is also the probability that the evening peak could have increased (relative to the morning peak).



3.4 What was the goal of South African TOU tariffs and how have the results reflected?

One of the original 'champions' of TOU tariffs, Andries Calitz, was Eskom's national Pricing Manager during the late 1980's and early 1990s. Several reference are attributed to him and some of work that will be mentioned repeatedly relates to his report available from Eskom's library in Sandton, *Priorities for Pricing Policy Development and Time-Of-Use Electricity Pricing in Eskom* [Calitz, 1989].

Calitz [1989] indicated that the following would influence the *load factor for demand*³:

- Calitz indicated that the reason for the relatively high load factor (at the time) was due to the relatively low level of domestic load. With increased levels of electrification and urbanisation, the situation was bound to change.
- The summer load tends to be considerably lower relative to the winter load. The increased popularity of air-conditioning load was expected to change the seasonal load ratios.
- South Africa had experienced an *economic slump* due to sanctions and political uncertainty during the 1980's. However, political change appeared imminent and this would inevitable affect the economy which could affect the demand.
- Demand side management by reticulators (municipalities) that were beneficial to them but may have an adverse effect on the national system.
- In response to tariffs load management by industry could affect demand.
- Growth in the secondary nine-to-five industry in South Africa.

Calitz [1989] focussed on load shifting and peak clipping in his report. He emphasised the need for DSM programmes at a time of surplus capacity in Eskom due to:

- *Sharp recent and future increases in the cost of new generating capacity, together with the need to conserve capital and protect the South African balance of payments*
- *...natural reduction in system load factors of demand.*
- *The need to keep electricity price at affordable levels by increasing the utilisation of Eskom's generating capacity.*

Calitz [1989]

³ The ratio of average demand to maximum demand for a specific period (day, week, year)

Calitz [1989] noted that the objectives of TOU pricing include increasing the LF by peak clipping and load shifting measures. His goal included:

- Shift load from the times of highest fuel costs to off-peak periods that are characterised by lower fuel costs.
- Conserve capacity.
- Improve LF

The *Integrated System Load Factor* is plotted in Figure 3-11 from data provided in Eskom Annual Report [Eskom, 1987, 1990, 1993, 1996, 1999, 2002, 2006, 2009].

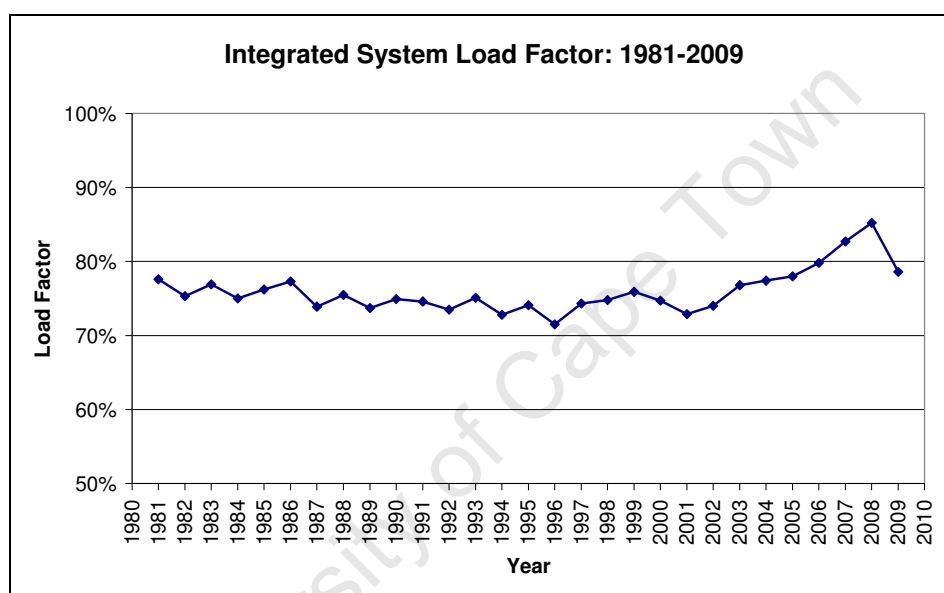


Figure 3-11 South Africa's Integrated System LF: 1981-2009⁴

TOU tariffs set out to improve the system's LF. The concern over a declining LF as described by Calitz [1989] is justified from the beginning of the study period until 1996. There appears to be a change for the next three years until 1999 before a decline until 2001. Thereafter, the LF has shown an increasing trend until a drop-off in 2009.

TOU have further set out to conserve capacity (especially during peak periods) and shift load to off-peak periods. The National demand patterns have shown some changes over the study period, including:

⁴ Data available in Appendix

- The Typical Winter day profile has shifted from a peak during the morning to an evening peak from 1992.
- The Typical Winter day profile has shown a 'flattening' of the morning peak in relation to the evening peak.
- The Typical Summer day profile has shifted from a peak during the morning to an evening peak from 1996.
- The peak day for the year appears consistently during the South African Winter season during the whole period of review.

It would appear that TOU tariffs might have achieved an increasing Integrated System LF (2002 onwards) and changed the national Electricity Demand pattern. However, there might be other factors that could have changed the Electricity Demand pattern and these factors need to be identified.

3.5 What are the barriers to TOU pricing in SA?

This section will start with the barriers to TOU tariffs that Calitz [1989] identified and discuss if they are still relevant in 2010. Thereafter, the impact of Nersa will be discussed, followed by comment on the impact of internal Eskom issues.

3.5.1 Issues as identified by Calitz

Calitz [1989] identified external *Pricing Considerations for Eskom*:

- The fact that *intermediate reticulators*, i.e. municipalities, supply the bulk of customers in SA requires *the integration of Eskom's electricity pricing philosophy and that of the reticulators*.

There might still be doubt if the municipalities supply the bulk of SA's customers; however, the integration of pricing philosophies remains problematic. More detail will be provided in Chapter 9 via a comparison with the region's largest municipality.

- The relatively small difference between summer and winter months' temperatures (compared to Europe) causes a *high annual system load factor for demand for electricity*.

Across South Africa the average change between the periods 1970-1989 and 1990-2006 was an increase of 0.27°C [Blignaut et al., 2009] with a mean annual temperature of about 24-25°C. This implies a fairly consistent climate

(from an electrical energy consumption perspective) between those periods.

Internally, he identified the following for Eskom consideration; comments will be given to indicate if reasoning is still relevant:

- The often long term *nature of Eskom's coal contracts with mining houses constrains short term marginal costing.*

However, this does not imply that short term contracts are necessarily the solution. It is mentioned in the Eskom's Annual Report 2009 that *short-term coal contracts* (to boost coal stock levels from 12 days to an average of 41 days) *and the significant escalation in the unit cost of coal* led to a substantial increase in money spent on primary energy. Increased primary energy costs could lead to increased costs for the different TOU periods. Coal fired power stations are normally part of *base load* power stations that is considered the least expensive to run from an operating cost perspective.

- *...adequate planned and installed generating plant margins, and the exclusion of quality of supply as a parameter in electricity pricing.*

This is not the case anymore as a *limited reserve margin became apparent in January 2008 when Eskom was forced to introduce emergency load shedding* [Eskom, 2009c]. With regard to quality of supply, *Premium power supplies* allow customers to *negotiate power quality that is superior to standard quality of power* [Eskom, 2009d].

- Limited information about customer demand profiles.

This is not the case anymore as customers, specifically large power users greater than 100kVA within Eskom supply areas, have sophisticated metering systems that enables the utility to determine demand profiles amongst other things.

- Unsuitability of some of Eskom's power stations due to the lack of their ability to *two-shift*. This term refers to the capacity of the power stations to operate at 2 levels of significantly different capacities to cater for the daily LF fluctuations.

In South Africa, base-load power stations run at maximum capacity for most of the day. As several of South Africa's older power stations were intended as regular base-load suppliers, it is hard for the plant to adjust to two-shift operation [Power Technology, 2009]. Some of these power stations were mothballed in the early 1990's and returned to service during the second half

of the first decade of the 2000's when lack of base load power stations became a problem.

- *Eskom is forced to also do planned maintenance during winter, possibly obviating the need for a seasonal component in time-of-use pricing.*

Although minimal maintenance is planned for the colder winter months due to increased demand (as shown in Chapter 3), the demand still peaks in the winter season. This means that generation's reserve margins are under even more pressure. This pressure *obviates* the need, still, for a seasonal component of TOU tariffs to indicate the reduced reserve margins.

3.5.2 What impact has Nersa had on TOU tariffs

The Electricity Regulation Act of 2006 [DME, 2006] makes Nersa the *custodian and enforcer of the regulatory framework*, including the electricity *tariff principles*:

- must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin of return;*
- must provide for or prescribe incentives for continued improvement of the technical and economic efficiency with which services are to be provided;*
- must give end users proper information regarding the costs that their consumption imposes on the licensee's business;*
- must avoid undue discrimination between customer categories;*
- may permit the cross-subsidy of tariffs to certain classes and customers.*

It is not always clear how these tariff principles are implemented as some of the principles could be interpreted differently. For example point a) states that the licensee can *recover the full costs of its licensed activities*; however, it does not necessarily state from whom those full costs are to be recovered. Should it be from its complete customer base or from selected customer groups via the tariffs or from an alternative source?

Point c) states that the end users should be given *proper information regarding costs that their consumption imposes on the licensee's business* but what is *proper information* and how does this translate to tariffs? Could this mean that if a group of customers' consumption profile indicate that they should be charged the highest rate if they incur the highest cost to the utility? However, this could be in conflict with point e) that allows for cross subsidisation should those particular customers be subsidised. What is considered *undue discrimination* as referred to in point d) as cross-subsidisation could be viewed as undue discrimination?

Eskom's interpretation of the tariff principles can be illustrated by:

While Eskom's average price (total revenue/total consumption) is based on cost, individual price levels per customer or per customer class might not be cost-reflective. This is due to cost averaging, historical cross-subsidies and social factors such as the customer's ability to pay the determined price. [Eskom, 2009d]

Consider the example of a remote farmer who is not close to the existing network. If he is charged the full cost of providing supply, he might not farm at all and the prospect of another farmer that could feed the nation is lost. Or, consider a farm worker who will never use electricity for anything other than media and light and use very little more than the allocated free basic electricity (FBE) for poor households. FBE refers to a program where poor residential customers benefit from 50kWh per month at no cost to the user. However, network infrastructure is required, first to be installed and later maintained, to ensure electricity is available to these customers. As these customers are not likely to be able to afford the full cost of making and keeping supply available, there is a need for alternative sources of funding, possibly from government via National Treasury and/or cross-subsidisation from other customers. Cross-subsidisation indicates the necessity for the *Electrification and rural subsidy (ERS)* which *is applied to the total active energy supplied in the month in kilowatt-hour. Not applicable to rural and small power user (SPU) tariffs* [Eskom, 2009d]. As rural and SPU customers do not contribute to ERS it appears that they could benefit from ERS.

Eskom appears to be aware of the risks of cross-subsidisation. Cross-subsidisation needs to be done while being considerate to the *subsidy base: If subsidies become too large, subsidising tariffs may also become unaffordable thereby eroding the subsidy base* [Eskom, 2009d].

The issue of cross-subsidisation becomes important as it appears almost in conflict with the aim of establishing cost reflective tariffs. As TOU tariffs is an attempt at establishing cost reflective tariffs, the task becomes even more challenging as the tariff now has to cater for non-related costs like cross-subsidies.

Cross-subsidies do not necessarily fund the FBE programmes. In Eskom supply areas, municipalities fund the FBE programmes as *provision of free basic services is,*

primarily, a social function that is the responsibility of government [DME, 2001] as illustrated by:

Eskom provides FBE in its supply areas and this is recoverable from municipalities at a standard tariff. Any under-recoveries from differences between the customer tariff and the applied free basic electricity standard tariff, implementation costs or other costs, are recoverable from government [Eskom, 2008].

The Eskom tariff proposal needs to be submitted to Nersa for approval.

Nersa pre-determines revenue limits based on prudent costs that it allows to be recovered through the tariff and a fair rate-of-return calculation on the regulated asset base. [Eskom, 2008]

Historically, Nersa will adjust the required revenue based on its own calculations relative to the Eskom submission and the adjusted revenue now needs to be fitted into the adjusted tariffs. Considering all the different tariffs, Eskom has to ensure with all the relevant stakeholders *the sustainable development of the industry but that it must avoid imposing unacceptable costs to the poor/or an excessive shock to the economy [Eskom, 2008].* This statement appears almost in conflict with point c) of the tariff principles as it implies that all customers cannot be given *proper information* (via tariffs) regarding the costs that they impose on the system.

The *poor* residential customer's tariff increase was limited to 15% when the average increase awarded to Eskom was 31.3% for the year starting 1 July 2009 [Eskom, 2009c]. The history of Eskom tariff increases is shown in Figure 3-12 in comparison to the Consumer Price Index (CPI). Tariff increases granted to Eskom have generally been lower than CPI that implies that the cost of electricity has been decreasing in real terms since 1988 till about 2002. Increases granted thereafter up to 2007 appear to be more closely related to CPI. The increase granted for 2007/2008 was 5.1% relative to the CPI of 7.1%. In 2008/2009 the increase was 27.5% versus the CPI of 10.3% with equivalent figures of 31.3% and 6.16% for 2009/2010 respectively [Eskom, 2009d]. Approved annual tariff increases granted from 2010 to 2012 were 24.8%, 25.8% and 25.9% for 1 April 2010, 1 April 2011 and 1 April 2012 respectively [Nersa, 2010].

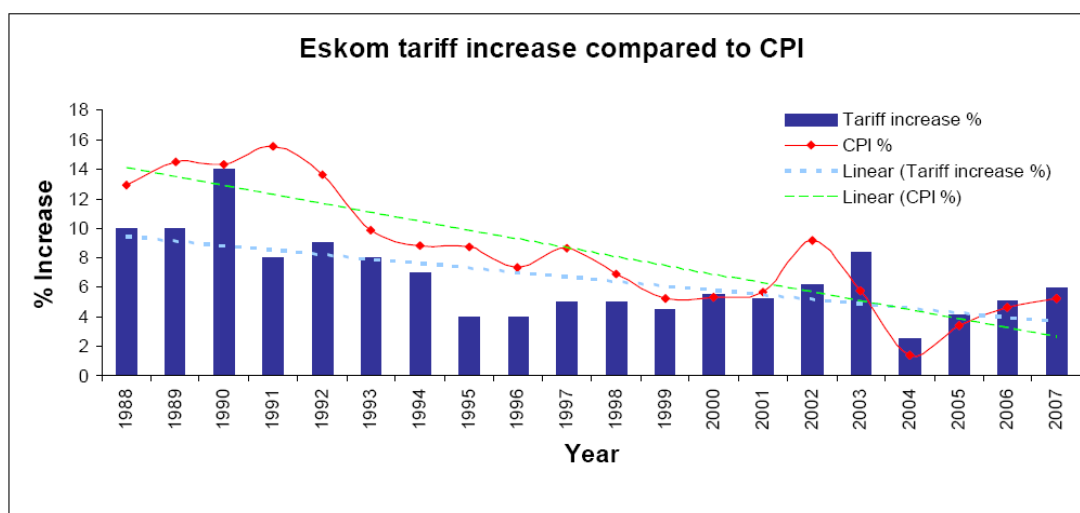


Figure 3-12 Eskom tariff increases [Ramokgopa, 2008]

The author's interpretation can be summarised: It has been illustrated that the process of establishing tariffs involves a complex balancing act. The licensee needs to have cost reflective tariffs (but not necessarily for all customers like the very poor), while there is a requirement for cross-subsidisation via the ERS without eroding the subsidy base while ensuring the sustainable development of the industry but without imposing unacceptable costs to the poor.

3.5.3 What internal Eskom issues could hamper further TOU implementation

There are internal issues to Eskom that could hamper further TOU implementation. One of these issues is how tariff pricing requirements are determined.

There are four major divisions to Eskom that make separate pricing submissions to Nersa for consideration. These include Distribution, KSACS, Transmission and Generation. The Distribution submission is broadly based on the Generation and Transmission submissions plus allowable additional costs and profit. It would appear that Nersa considers the separate submissions in isolation rather than as a group submission. This perception, at least internally to Eskom, is substantiated by: *Each division in Eskom is financially ringfenced and regulated separately.* [Eskom, 2008a]

Distribution Pricing submits a revenue proposal that it would like to recoup from the retail customer via the tariffs, while, in turn, Transmission and Generation submit

separate revenue proposal it would need to sustain and even expand its business to meet the growing demand in the country. Note that the KSACS submission is viewed by Nersa as the same as the Distribution submission.

As illustrated in Chapter Two, tariffs have the potential to adjust load profiles. Calitz [1989] indicated that TOU tariffs could be used to increase the system LF. In South Africa, it is not clear that the three Eskom divisions that make submissions make a consolidated submission that will cater for any system LF adjustment, and inherently load profile adjustment.

3.6 Can tariffs address/solve the national supply problem?

Before the question of addressing/solving the national supply problem can be answered, there has to be certainty about the nature of the national supply problem. As illustrated by the quote below, TOU rates have achieved varying measures of peak reductions in other countries:

The magnitude of reductions in peak period loads within the TOU class range from 1 to 10% for US utilities that have had TOU rates in effect for only one or two years. The longer term French and British data suggests that peak load reductions in the TOU class may reach between 13 and 35%, depending on the method used for analysis. [Acton et al, 1980]

As stated in Chapter Two, TOU tariffs were used to increase load factors and/or shift load from peak periods [Vickrey, 1971, Wenders et al, 1976, Acton et al, 1981, Park et al, 1984, Taylor et al, 1990].

However, as load shedding in South Africa occurred right through the day during 2007 and 2008 [Mail & Guardian, 2009], there seems to be an initial need for energy reduction throughout the day. Hence, at least in the short term, energy conservation (to avoid load shedding) might be viewed as more pertinent than peak reduction, increasing load factors and/or shifting load from peak periods.

Taylor [et al, 1990] suggested that besides shifting load in response to TOU tariffs, *households may also make changes that reduce consumption during all hours.* This implies that TOU tariffs create a greater awareness of electricity consumption that could ultimately lead to energy conservation benefits.

When the national demand profile is considered (sections 3.1 to 3.3) there still appears a need for generating plant that would only be used for the short peak periods. Therefore, peak reduction and/or shifting load from peak periods (leading to changing load factor and reduced need for additional peak generation) become ongoing needs and hence the primary goals of TOU tariffs could take centre stage again.

3.7 Chapter Summary

In order to assess if adequate answers have been provided to questions 2 to 5 of section 1.2 the following summary has been provided. In addition, the origins of South African TOU tariffs appear to have been adequately traced:

- The first form of TOU tariff was Tariff E. This was introduced in 1986 on request from AMEU for an 'off-peak tariff' where MD charges would only be charged from 07h00 to 23h00 on weekdays.
- The first energy related time-differentiated TOU tariffs were introduced in 1991 in South Africa.

The goals of TOU tariffs have been traced to Calitz [1989] and these include load shifting, increased load factor and capacity limitation. After a general decline during the 1990's, the Integrated System LF has shown an increasing trend from 2002 onwards. Further study is required to analyse these changes. Prior to 1992, the system repeatedly had a peak during the morning. By 1992 South Africa had developed an outright system peak during the evening. This has remained up to 2007 and the gap between the morning and evening peaks appears to have widened over time. The system continues to have an annual system peak during the colder winter months of June to August. The Summer Day profile has also consistently shown an evening peak from about 1996 onwards.

The morning peak appears to have flattened in relation to the evening peak between 1992 and 1995. It does appear that TOU tariffs have had a response from customers that were exposed to TOU tariffs. However, there is an equal probability that the evening peak could have increased in relation to an unchanging morning peak. There is enough doubt to say that impact of TOU tariffs might not be exclusive reason for these changes. Further study is required to identify and determine the impact of the other factors that may have influenced the changing demand patterns.

A literature search on the performance of the Western Region separately from the national entity of Eskom has not produced any noteworthy reading material. However, data is available to determine the characteristics of the large power users in the region. This will allow an assessment of TOU tariffs, and whether they have been effective in the Western Region, viewed as a sample of the whole.

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4. Methodology

Chapter Two and Three has identified areas that need to be considered before a conclusion can be drawn with respect to the effectiveness of TOU tariffs in South Africa.

From Chapter Two, the following facts were established:

- TOU tariffs have been used to change load factor and change the shape of demand profiles.
- Customers outside of South Africa that have been exposed to TOU tariffs do respond to tariffs.
- Peak-period price differentials influence the level of demand reduction significantly.
- However, the characteristics of a customer's response are not only based on the price differentials within TOU tariffs. Factors like climate, period that tariffs have been in place, appliance ownership etc. affect the way a customer responds.
- TOU tariffs may indirectly lead to greater energy conservation due to increased awareness of electricity consumption.
- All categories of customers could benefit from TOU tariffs.
- TOU tariffs can reduce demand during peak periods but might not be able to cater for ad hoc contingencies that occur outside peak periods.
- TOU tariffs should be considered the trigger for more dynamic tariffs that would be able to cater for short term contingencies and other 'add-on' features like reliability premiums.

From Chapter Three, it would appear that TOU tariffs could have contributed towards an increasing Integrated System Load Factor (2002 onwards) and changed the national Electricity Demand pattern of South Africa. However, other factors could have induced the same result with TOU tariffs acting as a modifier.

LPU's in the Western Region are a subset of LPU's across the country. The response of LPU's to TOU tariffs needs to be analysed to assess the impact of tariffs at a local level. This would test the hypothesis that TOU tariffs have been effective in the Western Region.

This chapter will discuss the details of the methodology employed for this analysis. Two broader areas will form the framework for the further structure of this thesis. First, the analysis of the available data will be discussed followed by a discussion of the findings of the analysis that includes potential future implications.

The analysis is based on data sources related to LPUs in the Western Region. As far as practically possible, customer identification detail is withheld from this study. This is possible in most cases because results from groups of customers will be analysed as opposed to individual customers. However, in some cases individual customers need to be discussed due to their impact on the overall system. Despite attempts not to disclose the identity of the customer, one would nonetheless be able to accurately guess a particular customer's identity. One such example is the City of Cape Town. Generally, data and results are intended to reveal trends and properties related to a customer type, but not the sensitive details of the customer.

Discretion will be exercised so as not to divulge sensitive information but still indicate the conclusions that were derived from the data.

LPUs provide an opportunity to analyse customer behaviour, particular in response to changing energy prices during the day and during the year. There were no previous reports of detailed and comprehensive data analysis prior to this project.

The LPU Analysis will be divided into three different segments:

1. Initial LPU analysis relating to seasonal response.
2. Specific Group analysis relating to seasonal response.
3. Specific Group analysis relating to daily response.

Before the details of LPU analysis is provided, the region's customer base is described followed by a description of the data sources.

4.1 Western Region customer base

Eskom is a public utility that generates approximately 95% of electricity used in South Africa. The utility is broadly divided into the Generation and Networks and Customer Service businesses, as well as the Corporate divisions that includes Finance, Corporate Services and Human Resources. Of direct interest to this thesis, the Generation Business division generates electricity, while the Network and Customer

Service business is responsible, amongst others, for transfer of the energy from the supplier to the local distributors. There are two types of distributors in the Western Region, viz. Eskom Distribution and the local municipalities.

In the Western Region, Eskom Distribution controls all the major supply intake points to the region that are supplied by Eskom Transmission. Broadly, Eskom Distribution operates the network that supplies customers. Eskom Distribution supplies customers that range from HV to LV, while also supplying other re-distributors or municipalities at different voltage levels. Eskom Key Sales and Customer Services (KSACS) was created to, amongst others, manage key large and international customer relationships who meet specific minimum usage criteria. The revenue generated by energy sales to Eskom KSACS customers is separate from Eskom Distribution and they are ultimately considered part of the Eskom Transmission Division.

The different municipalities supply a mix of industrial/commercial, agricultural and residential customers. The exact nature of that mixture is generally size dependant with the more rural and often smaller municipalities more residentially and agriculturally orientated. The bigger the municipality the more likely they will have a bigger proportion of industrial/commercial customers.

Eskom Distribution's customer base can broadly be divided into the following categories in the Western Region:

- Small Power Users (SPUs: supplies up to and including 100kVA)
- Prepaid Residential
- Conventional Residential
- LPUs (supplies of at least 100kVA)

To illustrate the relative contributions to the Western Region, the pie charts in Table 4-1[Eskom, 2009b] have been compiled with data starting April 2008. It is evident that even though the LPUs' number of accounts may only account for 1.1%, they consume 89.6% of the energy and contribute 80.1% to the Eskom Distribution, Western Region's revenue. The equivalent values for residential customers are 92.5%, 6.7% and 13% respectively. Municipalities are regarded as LPUs to Eskom and they supply the bulk of the residential customers in the Western Region (and the rest of South Africa). SPUs include supplies up to and including 100kVA that are

neither Residential nor LPUs. This could include small businesses and small agricultural type supplies.

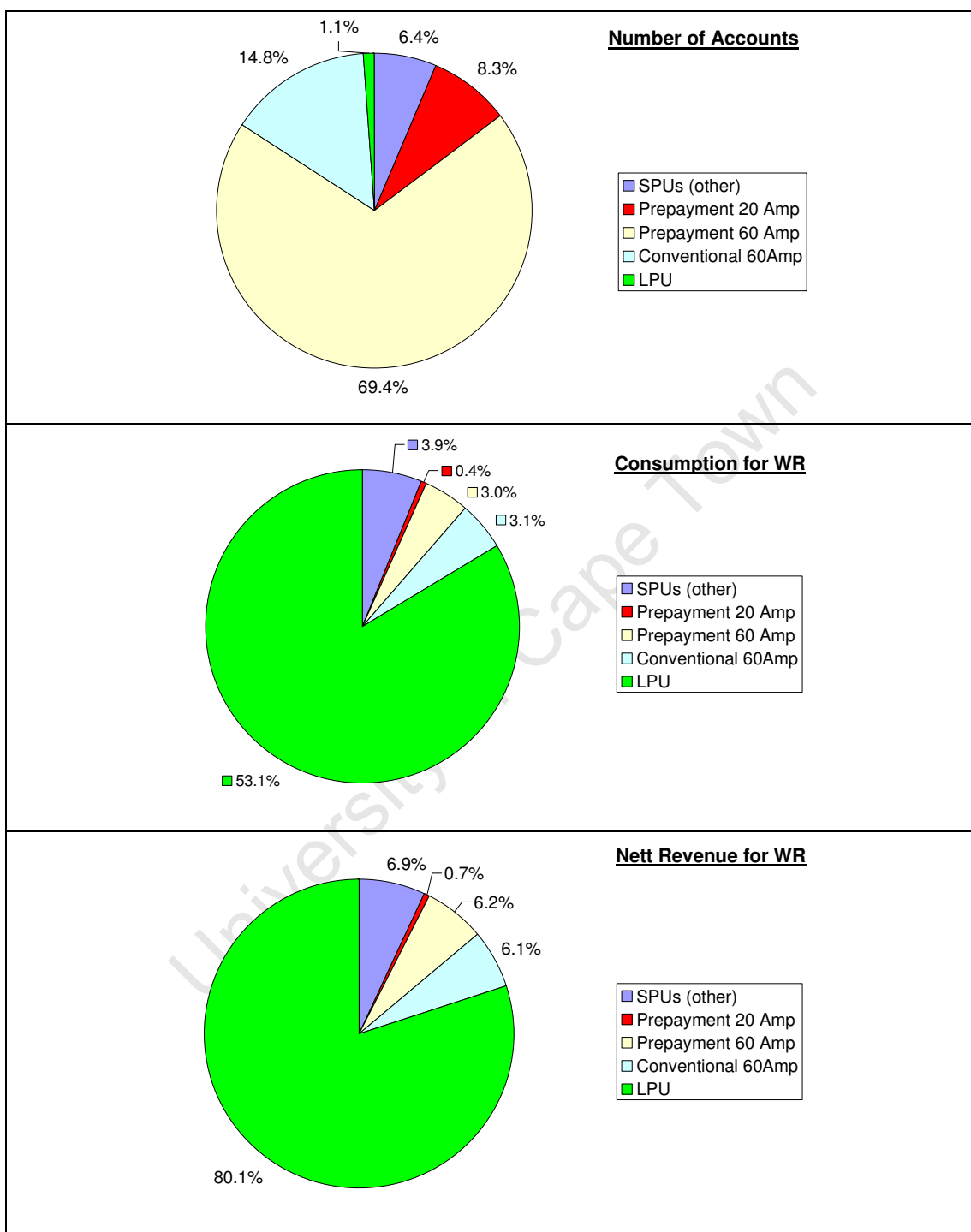


Table 4-1 Customer breakdown for the Western Region (total up to Feb 2009)

4.2 Data Sources

Three sources of data will be used to analyse LPU behaviour. They include:

- Half hourly integrated demand readings that are retrieved from the 'MV90' metering system per customer. This can be used to determine a customer's demand profile over relatively short periods like 1 day, 1 week, or a particular month. The same data can be manipulated to determine the customers' energy profile over the same period. Some downloads already exist since 1999 and are stored on Eskom's local servers as 'Profile data'. Others have to be downloaded and the period that can be specified could only include a two-year period.

This set of data will from now be called 'MV90 data' for ease of reference.

- Summary data stored per customer per month containing the maximum demand registered for a particular month, energy consumed for the month and amount owed by customer indicated on customer's electrical energy account. This can be used to plot a customer's annual demand and energy profiles with data stored per month. Some LPUs will have info stored in an existing database until 1999 while others will only go to as far as 2002.

This set of data will from now be called 'Summary data' for ease of reference.

- LPU details list: this list includes customer names with latest applicable tariffs, locations, account numbers, Notified Maximum Demand, Supply voltage, Point of Supply info like feeder and transformer, etc. This list is updated about once every six months.

This set of data will now be called 'Customer details data'. It is important for classifying customers in groups and disaggregating the MV90 and Summary data for analysis.

4.3 Initial LPU Analysis

LPUs are initially classified in two major groups. At this stage municipalities or redistributors are excluded as they do not represent one specific type of customer. As a redistributors they would also sell energy to a mixture of industrial/commercial, agricultural and residential customers. The purpose of the initial LPU analysis is to determine if there has been a correlation between customer response and the pricing signals of the TOU tariffs. Once a response has been confirmed, more detailed LPU analysis will be initiated.

The first group will be called 'larger LPUs', and the second, 'smaller LPUs'. There could be a difference between the ways that larger and smaller LPUs operate their businesses. One of the main reasons could be as a result of the relative financial impact of the customer's electrical energy expense. Smaller LPUs might spend a smaller or larger percentage of total expenses on electrical energy in comparison to larger LPUs. As the relative electrical energy expense could be different, the response to the tariffs could be different as well.

As implied by initial LPU descriptions, demand size, specifically Notified Maximum Demand (NMD), will be used as one of the initial differentiators between LPUs. NMD refers to the maximum demand defined in the contractual agreement that a customer signs with Eskom. The customer could pay a monthly fee to maintain access to the usage of the NMD.

Larger LPUs are classified as being supplied directly from an indoor medium voltage (MV) breaker/s that could be located at either a stepdown substation or protected MV switching substation. Demand is limited to between 2 and 10 MVA. These customers tend to have half hourly profile data already downloaded, some as far back as 1999, especially if the indoor breaker is located at a stepdown substation.

Larger LPUs were more likely to have fairly sophisticated metering installations at the time when the customer's supply was commissioned for the first time. This type of metering was the standard metering available for indoor MV breakers. When the initial Summary data was downloaded greater emphasis was put on larger LPUs who were more likely to be supplied from an indoor breaker. Information would likely be available from 1999 onwards.

Smaller LPUs are supplied typically away from a stepdown or protected switching substation. They are supplied via a tee-off from an MV feeder that may be underground or overhead. They could have either an MV or low voltage (LV) supply. The LV supply is achieved by a pole/ground mounted transformer or one of the different varieties of minisubs. A minisub is ground mounted, fully metal enclosed substation with a transformer, LV switchgear and limited MV switchgear. An MV supply could include a combination of MV metering plus an MV supply point via either pole mounted fuses, switches, ring main units or reclosers. Generally, the NMD would not exceed 1MVA. However, there are a limited number of customers

whose NMD does exceed 1MVA (but does not exceed 2MVA) but supplied from a tee-off from an MV feeder and will be included in the smaller LPU sample as they would not dominate the group's profiles.

Smaller LPUs, especially the 'older' ones, would not have as sophisticated metering as for larger LPUs. The older metering would have required physical visits to the customer's premises in order to download consumption and demand data in order to determine the monthly bill for the customer. A regional LPU metering upgrade project was initiated in the late 1990's whereby remote smaller LPUs could be accessed from selected workstations to download metering information. Readings are available from 2002.

Larger LPUs were selected randomly but for the following criteria:

- Summary data should be complete to as far as January 1999.
- Customer should not be a municipality or some form of 'redistributor'.
- A 10MVA limit was chosen so that very large LPUs do not dominate/skew the overall analysis.

Smaller LPUs were also selected randomly but for the following criteria:

- Summary data should be complete to as far as January 2002.
- Customer should not be a municipality or some form of 'redistributor' and would be limited to 2MVA.

The analysis of the results of the use of random LPUs across the region and from all facets of business and industry should justify further detailed analysis of LPU behaviour. This will lead to the analysis of specific customer groups.

There are over 3600 active LPUs on the Western Region database. The size of the whole population does not allow for all LPUs to be considered. Therefore, a sample will be used to represent the two groups comprising the Larger and Smaller LPUs. At least 30 customers (all complying to the above criteria) from the Large and Smaller LPU groups will be used for the analysis. *Many texts suggest that n is sufficiently large to assume the Central Limit Theorem whenever $n \geq 30$* [Vining et al, 2006]. The LPU breakdown is illustrated in Table 4-2.

Range of customer NMD (MVA)	All customers	Summated NMD (All):	No. of Municipal supply points	Summated Municipal NMD (Municipal)
> 5MVA	119	3,911,605	74	2,607,550
>1 and ≤5	210	554,018	59	158,750
≤1MVA	3302	828,698	168	56,587
Totals	3631	5,294,321	301	2,822,887

Table 4-2 LPU Breakdown

The process to determine the characteristics of Larger and Smaller LPUs' profiles needs to consider information sensitivity with respect to demand, energy and load factor (LF) readings. One needs to consider growth and decline, while being aware of irregular spikes or dips to ensure that anomalies do not skew the findings. In this light an appropriate analytical technique is required to ensure that the most appropriate conclusions are drawn.

A technique is required to identify seasonal variation of demand and energy. A Box-Jenkins based approach will be used that includes the following steps:

- Calculate the 12-month moving average for demand, energy and LF readings.
- Calculate the monthly index for demand, energy and LF readings.
- Calculate the mean, standard deviation of the monthly index.
- Plot graphs for demand, energy and LF with mean plus standard deviation and mean minus standard deviation envelopes.

These steps will produce a plot for 12 months with a positive and negative standard deviation envelope (to assess how much the monthly index values vary) for the period 1999-2008.

4.4 Tariff description

From Chapter Two, peak-period price differentials influence the level of demand reduction significantly. LPUs are exposed to a range of different TOU tariffs. A brief description will be offered to gain context for the LPU analysis including peak-period price differentials.

4.5 Specific Customer Group Analysis

In Chapter Two it was stated that many types of customers could benefit from TOU tariffs. In addition, many types of customers outside South Africa that have been exposed to TOU tariffs have responded to the pricing signal. Specific customer groups were chosen so that similar type customers could be grouped together. It is assumed that specific customers in a specific customer group would respond similarly to pricing signals as their business environment is affected by similar issues. This section will describe how the response of specific customer groups to the seasonal and daily pricing signals of TOU tariffs will be assessed.

Customer details data has more information about individual customers other than NMD, customer name or customer account number. It also stores information about address, supply feeder and supply points, specific tariff, supply voltage, type of industry the customer is in, whether the customer is a KSACS customer, Eskom account number, etc. This information will be used to divide customers into the specified customer groups as detailed below.

Five different customer groupings within the LPU customer base were identified:

- Rural customers: these would typically include the customer participating in the agricultural industry, excluding rural municipalities. They would typically be exposed to one of the Ruraflex tariff variations.
- Rural Municipalities: The Western Region stretches from Cape Town in a northerly direction up to the Namibian border on the Cape West Coast, eastwards as far as Plettenberg Bay, and into the Upington supply area (up to Botswana). The largest municipality would naturally include the largest city in the region while the rural municipalities would be responsible for the rest of the towns in the Western Region. These municipalities would typically be exposed to either the Nightsave or Megaflex tariffs. Nightsave tariffs are suitable for high *LF customers* while Megaflex is more suitable for customers who can *shift load* [Eskom, 2008c].
- 'Non-agricultural' customers: these would typically include customers that are not considered agricultural but would be more industrially or commercially orientated. They would typically be exposed to either of Nightsave, Megaflex or Miniflex tariffs.
- KSACS customers: these customers are generally industrial and transport orientated customers but are not considered regional customers. They tend to

be much larger than the non-agricultural customers who are considered Western Region customers. However, as they are supplied from the regional network, they do have an impact on the regional profiles and thus have to be considered.

- The largest municipality in the Western Region, City of Cape Town (CCT) is the final customer group. CCT is considered a group as they have multiple supply points in the greater Cape Town vicinity, some of which are metered on Nightsave, Megaflex or Miniflex tariffs.

At least 30 different customer supply points will be considered for each specific customer group. The 30 largest supply points for each group will be used with the only criteria that the available data should be available for the study period. It is acknowledged that the 30 largest supply points would not be a statistically representative sample of the group as whole but might represent a significant proportion of the group from a NMD perspective. The 'significance' will be quantified during the seasonal analysis. Where the significance is 'less significant', a random sample of 30 will be taken from the remainder of the LPUs (i.e. without the 30 largest) in that particular group as a comparison to indicate and discuss any discrepancies.

The seasonal profiles for the customer groups will first be determined to determine any correlation to the seasonal aspects of TOU tariffs, followed by a weekly profile to determine any correlation to the time differentiated periods of the TOU tariffs. In both cases, the regional profile will first be determined as a reference for the specific groups to determine any regional correlations.

The Box-Jenkins approach will again be used. However, the timeframes are different because the period 2004-2008 will be considered to analyse the seasonal response. The timeframes for this specific study has been reduced as it was difficult to find a set of 30 customers per group with complete data as far back as 1999 or 2002 with reference to the Larger and Smaller LPUs respectively. Omitted data would affect the Summary data especially as certain individual months or, in some cases, consecutive months would not be populated. This could be attributed to a range of reasons including technical problems with the metering units, communication problems with the downloading of the metering units, temporary customer disconnections due to non-payment, etc. It was found that 2004 provided a common starting point for all the groups that catered for complete data for 30 customers per group.

The weekly profile will be compiled from data starting on 30 June 2008 to 27 July 2008. Instead of a 12 month moving average, a 7 day moving average based on 336 half-hourly readings will be determined to eventually produce a typical profile for the week of July 2008. The month is started on 30 June 2008 as this is a Monday with the need to consider four full weeks. The month of July 2008 is selected because the country and region's annual peak occurred in the same month. Note that a 7-day profile is compiled to assess the daily time differentiated response. This is deemed more representative than just choosing one particular day of the week.

As stated in Chapter 3, there are generally two types of metering philosophies employed by Eskom, viz. Large Power User (LPU) and Small Power User (SPU) metering. Each philosophy is associated with different technologies to meet the respective requirements. LPUs could be charged at time differentiated energy rates plus a possible demand charge (tariff dependent). SPUs are charged at the same energy rate that is independent of time. Residential customers are regarded as SPUs. Even though individual residential customers are not LPUs, their overall impact could be significant due to their volumes. It is therefore important to consider their profiles for the same study periods as used for the specific groups.

From Chapter Two, residential appliance ownership influences customer response. It makes sense that the level of appliance ownership is very likely related to the customer financial standing as demonstrated by the various All Media Products Survey (AMPS) reports. These reports refer to the different Living Standards Measurement (LSM) that categorises customers in terms of their wealth and associated material belongings that includes electrical appliance ownership. Residential customers will be divided into three groups as per the LSM definitions - details will be provided in Chapter Six. Areas were identified that would typically represent these different residential groups that are supplied from an Eskom substation with suitable metering facilities. This metering is at least on par with LPU metering and would be able to provide data that can be used to compile a seasonal and weekly profile.

4.6 Discussion

From Chapter Two, there are external conditions like climate, longevity of TOU programme, etc. that affect the characteristics of the response. Once the profiles

have been compiled for the seasonal and daily response of the different LPU groups, the possible factors per LPU group will be analysed to determine any correlation. Issues that influence the LPUs' profiles, and hence the regional profile, would have been identified. These issues will be discussed in detail in order to understand and recommend possible counter measures.

As TOU tariffs in South Africa were championed by Calitz, it would be appropriate to reflect on the demand patterns in relation to the original intentions as described by Calitz [1989].

The thesis will conclude with some final words regarding the effectiveness of TOU tariffs in the Western Region.

University of Cape Town

5. Initial LPU Analysis

As no protocol was known to the author and with a considerable volume of data to consider, an initial high level analysis became necessary to determine the approach for further study on more detailed customer groups.

Analysis was done in an exploratory fashion to determine the most useful method for further detailed analysis. Certain tables and figures (in this case, graphs) will represent information that will not necessarily be presented in the same way or in any way for the detailed customer groups in subsequent chapters. However, they indicate the need for further, but more focussed investigation.

Larger and Smaller LPUs' data will be summated in the same way to deliver similar outputs to determine if there are differences between the initial two groups of LPUs. As stated in Chapter Four, the Box-Jenkins approach was used to analyse the summated data.

5.1 Larger LPUs

Thirty larger LPUs were selected as per selection criteria described in Chapter Four. The results of the demand, energy and LF analysis follows.

5.1.1 Sum of MD, Larger LPUs

Monthly MD readings were summated for the 30 customers per month for the period being considered. These customers are charged on a mixture of Nightsave, Miniflex and Megaflex tariffs. All three tariffs are considered types of TOU tariffs that aim to reduce Peak period usage in relation to Off-peak period usage. Hence, this makes the result of the analysis useful in terms of the effectiveness of TOU tariffs in general.

The monthly MD readings from the Summary data source give no indication of time of month when this demand was registered. Therefore, the Sum of MD readings would be undiversified. Diversity can only be established when MV90 data is summated as this data is time stamped.

The undiversified MD readings (relative to the time and day of the particular month) were then exposed to the Box-Jenkins approach and logged against the particular months to compile the graph as shown in Figure 5-1. The winter period is indicated by the blue shaded area which coincides with the High Demand Season where energy and demand are more expensive in Eskom supply areas. The rest of the year is called the Low Demand Season from an Eskom tariff perspective. The national supply system is typically at its most vulnerable during the High Demand Season when supply reserve margins are at their lowest; this leads to higher electricity prices during this season as an incentive to avoid energy usage. However, it should be noted that reserve margins are also affected by maintenance scheduling that is not limited to a particular season.

From Figure 5-1 the Monthly Index is an indication of the seasonal variation from the Box-Jenkins analysis. It can be seen that larger LPUs tend to peak during March to April while registering their minimum during November for the study period. There is a general decline from the March peak to the November minimum.

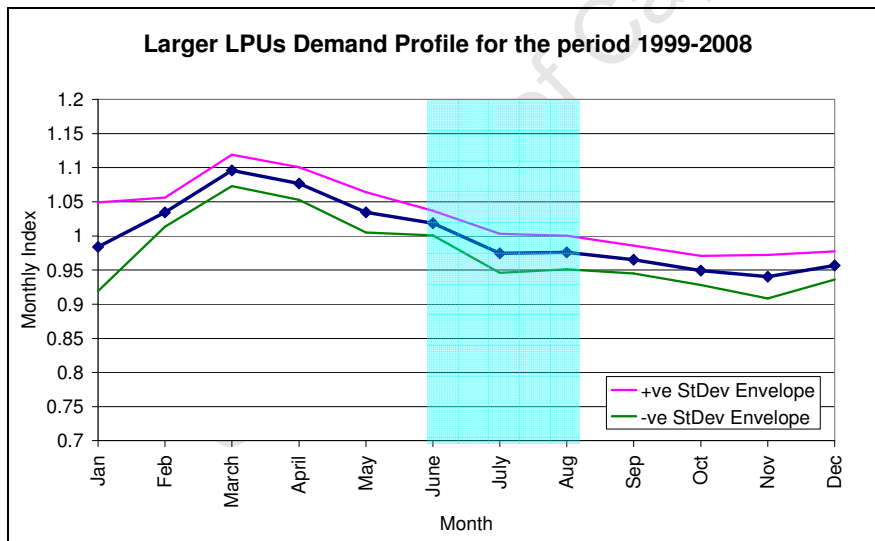


Figure 5-1 Larger LPUs Demand (Blue shaded area represents the High Demand Season)

5.1.2 Summary data: Sum of Energy, Larger LPUs

From Figure 5-2 it can be seen that larger LPUs tend to use more energy between March and April while registering their minimum during January for the study period. Considering the similar finding from a peak demand perspective, these findings would suggest that larger LPUs peak during the Low Demand Season which

correlates with less expensive energy and demand costs. However, it is noted that after the High Demand Season ends in August, there is not a similar increase in the subsequent months. This is a possible indication that the decline during the High Demand Season might be influenced by other factors and not restricted to the higher electricity costs of the season.

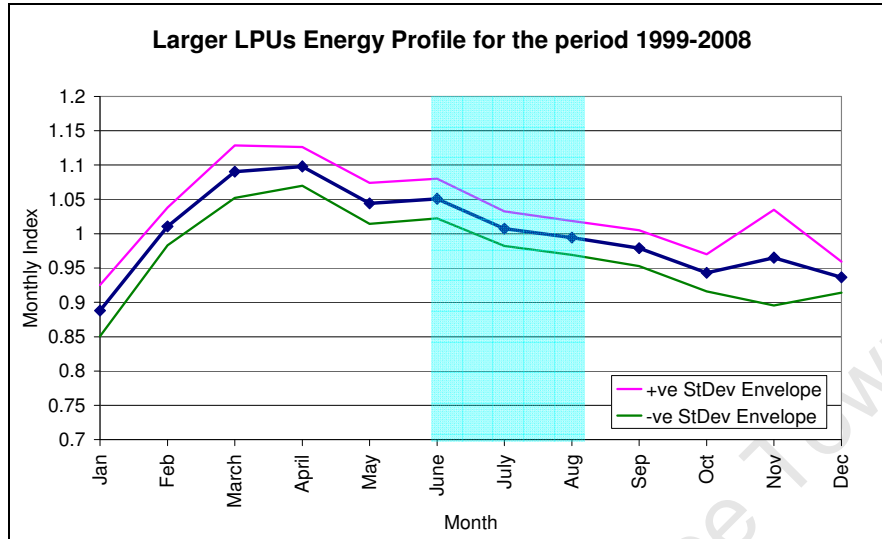


Figure 5-2 Larger LPUs Energy

5.1.3 Summary data: Seasonal LF comparison, Larger LPUs

The LF for the study period appears consistent other than a lower value for January (Figure 5-3). However, this could be attributed to industry having scaled down activities over the country’s annual holiday season. This theory is supported by the lowest Energy monthly index for the same month as well. The Demand, Energy and LF profiles are summarised in Table 5-1.

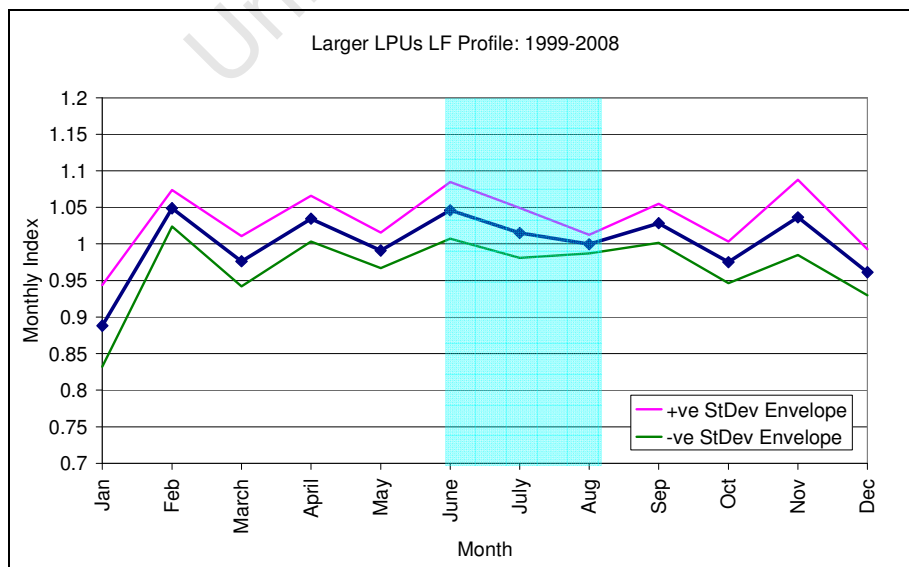


Figure 5-3 LF Seasonal Comparison

	Demand	Energy	LF
Average Low Demand Season Monthly Index	1.004	0.995	0.993
Average High Demand Season Monthly Index	0.990	1.018	1.020
Ratio of HD Average to LD Average	0.986	1.023	1.027
Max Monthly Index	1.096	1.098	1.049
Peak Month	March	April	Feb
Min Monthly Index	0.940	0.888	0.888
Min Month	Nov	Jan	Jan

Table 5-1 Larger LPUs Summary

The correctness of the LF Monthly Index warrants further discussion. The LF was calculated by summing the monthly maximum demand per LPU (undiversified). This undiversified demand was divided by the monthly total energy readings to determine the monthly LF. Therefore, this is not a true reflection of the LF because a summated diversified demand should have been used for a more correct representation. As this is not possible, the LF analysis will be discarded.

5.2 Smaller LPUs

The 44 Smaller LPUs being considered are on versions of the Nigtsave, Miniflex and Ruraflex tariffs. As for the larger LPUs, the data for smaller LPUs were arranged similarly. Data from January 2002 to December 2008 was used for Smaller LPUs.

5.2.1 Sum of MD, Smaller LPUs

These customers appear to peak in April while registering the lowest monthly index for demand in August in Figure 5-4. Note the increase in demand after the High Demand Season; however, the same levels prior to the High Demand Season are not reached. It would appear that Smaller LPUs tend to avoid the expensive winter season from a MD perspective.

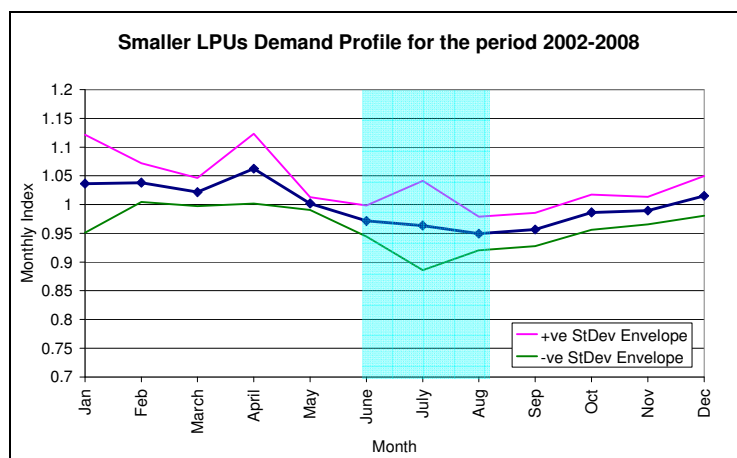
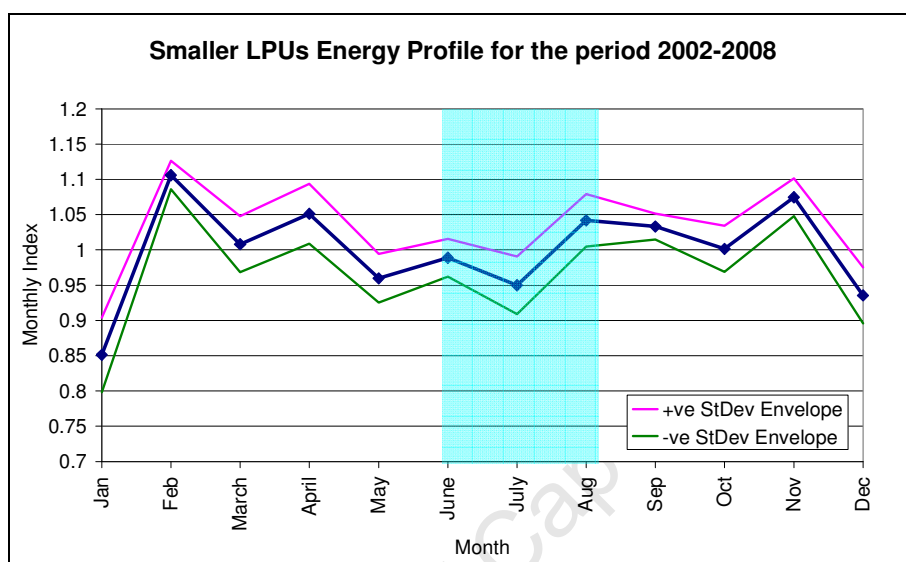


Figure 5-4 Smaller LPUs Demand**5.2.2 Sum of Energy, Smaller LPUs**

It would appear that Smaller LPUs peak in February for the study period with a minimum registered in January as shown in Figure 5-5. There is a decrease during the High Demand Season, followed by a subsequent increase in Energy consumption after the High Demand Season.

**Figure 5-5 Smaller LPUs Energy**

As for Larger LPUs, the January minimum correlates with the Energy minimum. Demand and Energy values are summarised in Table 5-2.

	Demand	Energy
Average Low Demand Season Monthly Index	1.012	1.002
Average High Demand Season Monthly Index	0.961	0.994
Ratio of HD Average to LD Average	0.950	0.991
Max Monthly Index	1.062	1.106
Peak Month	April	Feb
Min Monthly Index	0.949	0.851
Min Month	Aug	Jan

Table 5-2 Smaller LPUs Summary

In summary, it would appear that Larger and Smaller LPUs peak during the Low Demand Season and tend to scale down electricity usage during the High Demand Season. However, only Smaller LPUs tend to increase electricity usage after August month. The decreased usage during the High Demand Season does correlate with

the increased costs of Eskom's TOU tariffs. However, there may be other factors that could have influenced the profiles and these need to be determined.

5.3 Tariff description

From Chapter Two, peak-period price differentials influence the demand reduction of customers. It would thus be appropriate to consider some of the details of some of the different tariffs that could influence customer response. Details are presented in ratios to illustrate differences between seasons and daily periods; this will give some indication of the pricing signal of the particular tariff. The ratios that will be presented include:

Standard to Peak ratio, HDS: this illustrates the extent of pricing signal during the High Demand Season to avoid the Peak period and rather choose the Standard period for energy usage.

Off-peak to Peak ratio, HDS: this illustrates the extent of the pricing signal during the High Demand Season to avoid the Peak period and rather choose the Off-peak period for energy usage.

Peak/Std/Off-peak period seasonal ratio: this shows the ratios between the LDS Peak /Std/Off-peak periods' charges and the equivalent HDS charges to illustrate the extent of the seasonal pricing signal for that particular period.

The different times of the day that is applicable to Miniflex, Megaflex and Ruraflex is shown in Figure 5-6. More detail for annual tariff detail in Appendix.

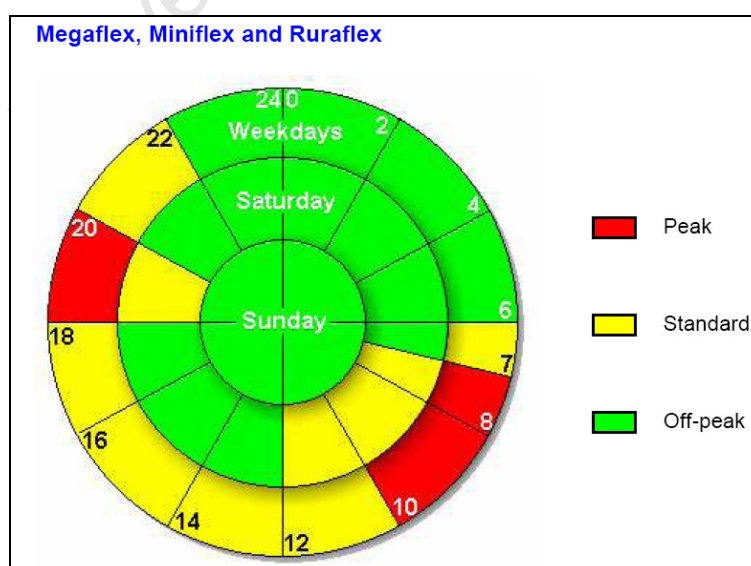


Figure 5-6 Megaflex, Miniflex and Ruraflex time periods [Eskom, 2008a]

5.3.1 Miniflex Tariff

Miniflex tariff ratios are shown in Figure 5-7. This is a TOU tariff for urban customers with an NMD from 25kVA up to 5MVA, characterised by:

Seasonally and time differentiated c/kWh active energy charges.

Three time-of-use periods name Peak, Standard and Off-peak.

Network Access Charge based on contracted notified maximum demand.

The decrease in 2005 can be attributed to a structural change when a Network Access Charge was introduced. Thereafter, the ratios have remained consistent.

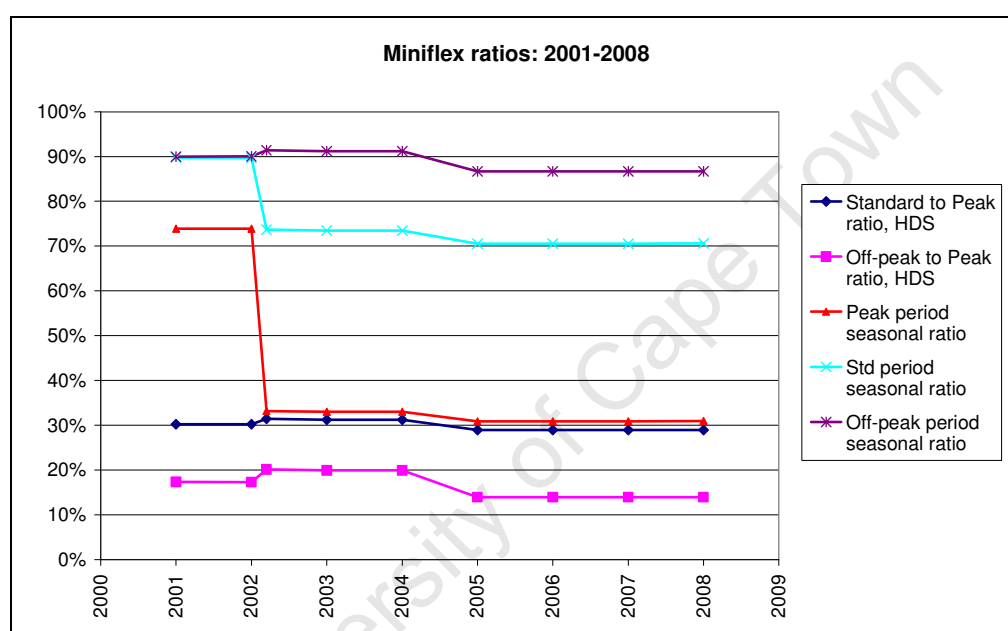


Figure 5-7 Miniflex ratios: 2001-2008

5.3.2 Megaflex Tariff

This is a TOU tariff for urban customer with NMD > 1MVA that are able to shift load with the same characteristics as Miniflex but with a R/kVA network demand charge applicable during Peak and Standard periods only. Ratios are shown in Figure 5-8.

The decrease in 2005 can be attributed to a structural change when a Network Access Charge was introduced. Thereafter, the ratios have remained consistent.

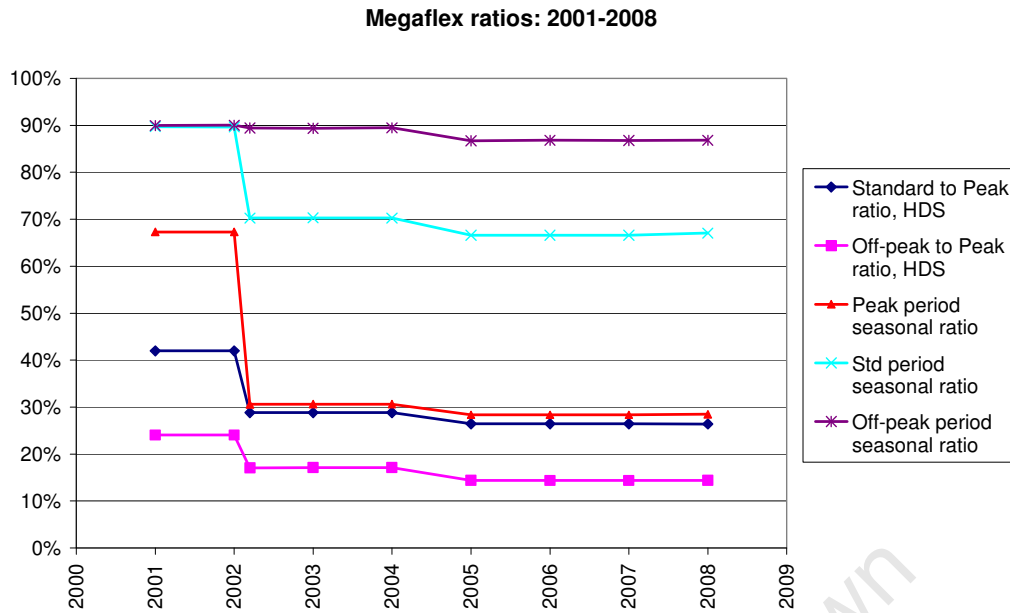


Figure 5-8 Megaflex ratios: 2001-2008

5.3.3 Ruraflex

This is a TOU tariff for rural customers with an NMD from 25kVA with similar characteristics as Miniflex. The Network Access Charge is lower and the energy charges are higher in comparison to Miniflex. Ratios are shown in Figure 5-9.

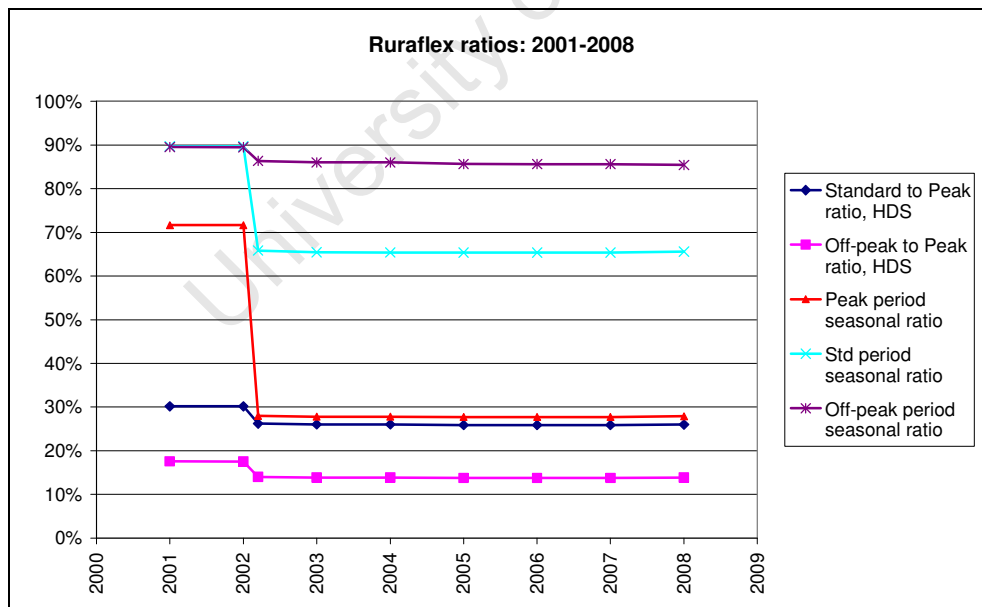


Figure 5-9 Ruraflex ratios: 2001-2008

It is evident that ratios have remained consistent since 2002.

5.3.4 Nightsave (Urban)

This tariff is for urban customers with NMD > 25kVA characterised by:

Seasonally differentiated energy demand and active energy charges.

Two time periods, viz. Peak and Off-peak (Figure 5-11).

Network access charge based on contracted notified maximum demand.

Network demand charge and energy demand charge applicable during Peak periods.

Ratios are shown in Figure 5-10. Different ratios are evident as the Nightsave tariff experienced structural changes that did not allow similar comparisons as for the other tariffs.

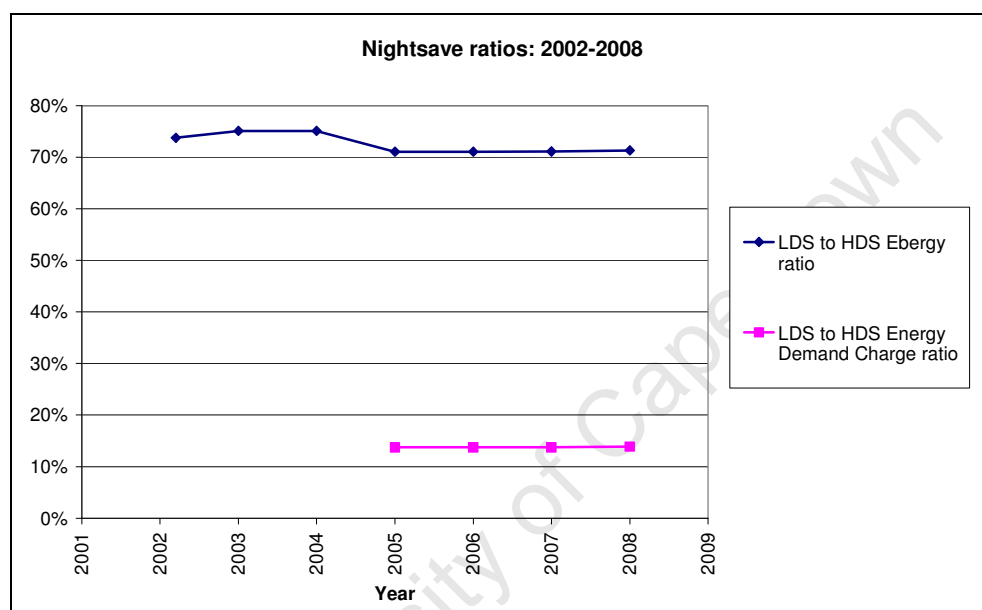


Figure 5-10 Nightsave Urban ratios: 2002-2008

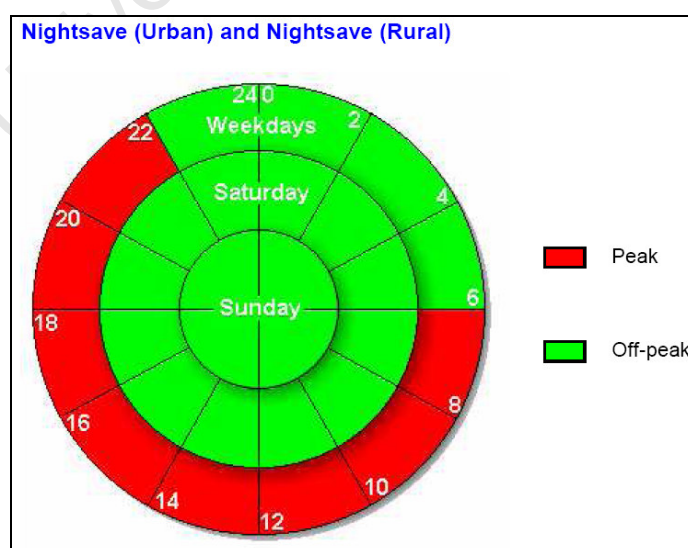


Figure 5-11 Nightsave time periods [Eskom, 2008a]

5.4 Chapter Summary

It has been shown that the initial LPU classification of Larger and Smaller LPUs confirms that the annual demand of the specific groups peak in the Low Demand Season, specifically February to April.

These same groups have also confirmed that their energy peaks occur outside the High Demand Seasons.

Larger and Smaller LPUs do not have similar profiles.

This chapter has highlighted that from a seasonal perspective, there is a correlation between the higher costs charged during the High Demand Season and reduced demand and energy consumption for Larger and Smaller LPUs. However, the country still peaks during the High Demand Season which is a trigger to investigate the response of LPUs to TOU tariffs at a more in-depth level.

There were differences in the response between Larger and Smaller LPUs. Larger LPUs' demand and energy monthly indices tended to decrease as the High Demand Season approached but did not show a subsequent increase after the High Demand Season. Smaller LPUs showed a similar decrease during the High Demand Season but did indicate an increase subsequently, albeit not to the same levels prior to the High Demand Season. Therefore, this is a trigger for more detailed customer classification when the in-depth investigation is conducted.

After considering some of tariffs that LPUs are exposed to, it is evident that the pricing signals of the different tariffs illustrated by similar ratios from year to year from have been consistent from at least 2005 onwards.

6. Western Region Analysis: Seasonal Response

Eskom Distribution supplies load in all nine provinces at various voltage levels and has been divided into six regions that can be separated along geographical lines that are not necessarily aligned to the country's provincial boundaries. The majority of the Western Cape Province and a small portion of the Northern Cape Province fall within Eskom Distribution, Western Region.

This chapter discusses the following:

1. The Western Region demand and energy profiles is analysed to determine the characteristics of the region.
2. Criteria are established to separate LPUs into different customer groupings.
3. Each LPU customer group's seasonal behaviour is analysed to determine a possible correlation to the Western Region's overall demand profiles.
4. Each LPU customer group is analysed to determine if there is a correlation between their usage and the different seasons of the tariff, i.e. the difference in usage between the High- and Low Demand seasons.
5. Typical Eskom Residential customers' consumption profiles are analysed to determine any correlation that might exist with the Western Region's overall demand profiles.

The Box-Jenkins tool will be used to analyse the different LPU customer groups and the different typical Eskom Residential areas.

6.1 Western Region's Demand and Energy profile analysis

The Western Region is supplied from various Transmission substations located within the region. When hourly demand and energy readings are summated, regional demand and energy values, respectively, are determined. Maximum demand values (after diversity) and energy summations are determined for the month that are then analysed using the Box-Jenkins approach as described earlier to produce Figure 6-1 and Figure 6-2. The Western Region profiles have the following characteristics over the period from 2004 to 2008:

- An annual demand and energy peak during the High Demand Season, not necessarily in the same month of that season.

- The ratio of the average High Demand Season monthly index to the average Low Demand Season monthly index for demand and energy respectively is 1.059 and 1.041.
- Tapering off of demand during the Low Demand Season with December being the most common month for the minimum of the year.
- Demand generally inclines from January till the High Demand Season; thereafter demand generally declines until December.
- Energy seems to fluctuate more with a general increasing trend from January to the High Demand Season with a more consistent decline to December.

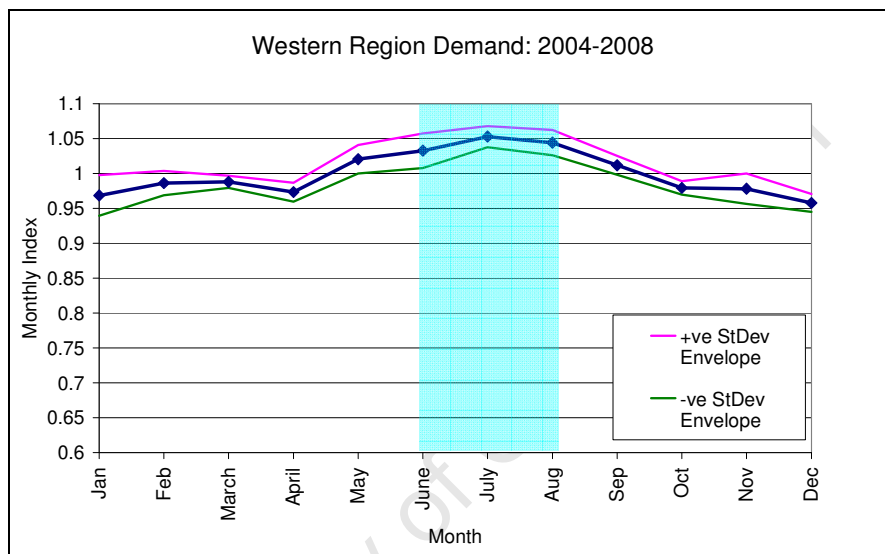


Figure 6-1 Western Region Demand profile: 2004-2008 [Eskom, 2009a]

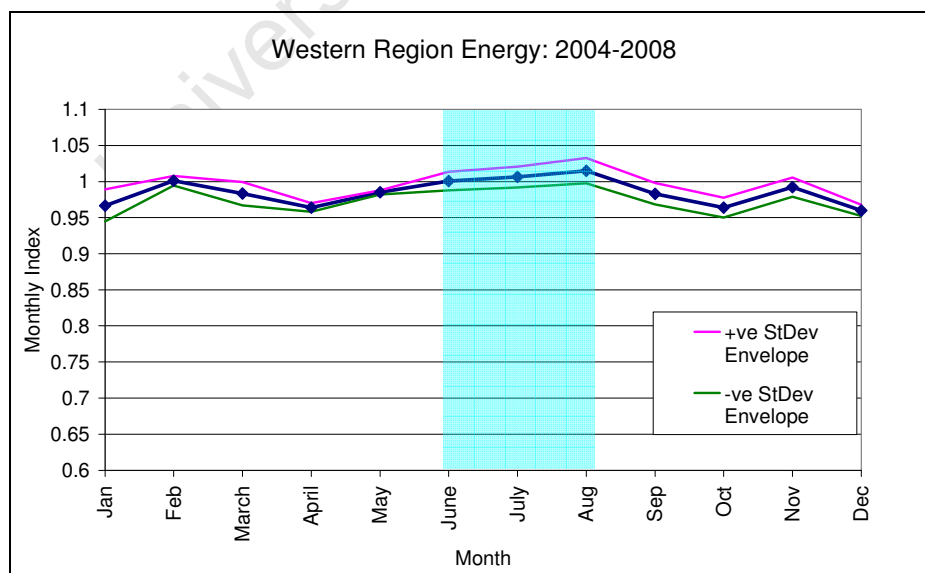


Figure 6-2 Western Region Energy profile: 2004-2008 [Eskom, 2009a]

The above description can be summarised in Table 6-1. This format is chosen to describe the different groups of LPUs.

	Demand	Energy
Average Low Demand Season Monthly Index	0.985	0.978
Average High Demand Season Monthly Index	1.043	1.007
Ratio of HD Average to LD Average	1.059	1.030
Max Monthly Index	1.053	1.015
Peak Month	July	Aug
Min Monthly Index	0.958	0.960
Min Month	Dec	Dec

Table 6-1 Western Region Annual Demand and Energy Summary: 2004-2008

Figure 6-1 and Figure 6-2 indicate that the shape of the Western Region's annual demand profile still shows a high demand season peak even though it has been shown that randomly chosen LPUs (Chapter 5) from different sectors peak outside the high demand season.

It has been shown that there is a correlation between the seasonal aspect of the TOU tariffs (more expensive) and the LPUs' lower demand and energy profiles. In addition, Western Region purchases electrical energy at the WEPS rate that has a similar pricing structure (in terms of higher High Demand Season charges). However, the region is still peaking in the High Demand Season. This leads to the question: *Why is the region still peaking in the High Demand Season?*

The groups of LPUs that were discussed form part of the greater Western Region. If LPUs play such an important role in terms of revenue and energy sales (Chapter Four), how do they impact the individual profiles of the Western Region?

6.2 Western Region's largest customer, City of Cape Town

The Western Region has several large customers that have a contracted MD of greater than 100MVA (compared to the region's MD in excess of 4000MVA in 2008). These customers are expected to have a significant impact on the shape of the Western Region's different profiles, simply because of their size. The biggest of these is the largest re-distributor in the Western Region, the City of Cape Town (CCT).

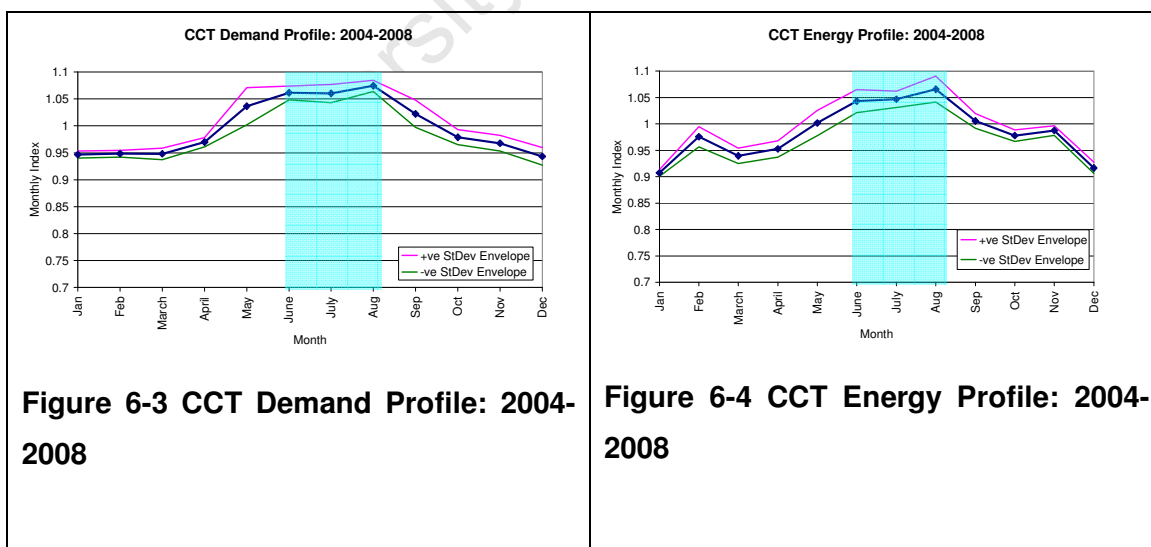
This is the only group of customers that is being identified by name in this study as attempting to conceal their identity would be futile as it is easily identified. However,

the Box-Jenkins approach provides seasonal indices that do not require disclosure of potentially sensitive information.

CCT have several supply intake points of various sizes to supply different sized loads from the biggest city in the Western Region to certain single phase LV supplies to supply a small office in an Eskom area of supply. The undiversified total of their contracted demands of their LPU supplies exceeds 40% of the Western Region's overall LPU demand. They supply the majority of the Western Region's residential customers.

Importantly, their major supply point that constitutes more than half the demand of their total supply is on the Nightsave Urban tariff. They are the only metropolitan city in South Africa that is not on a Megaflex tariff. Note that the majority of their smaller intake points are on the Megaflex tariff. The sample of 39 largest supply points represent 97.9% of the total notified maximum demand (NMD) for the CCT and hence represents a significant proportion of this customer's load.

The profiles for the CCT in Figure 6-3 and Figure 6-4 show a strong correlation with the Western Region's profiles as shown earlier with clear High Demand Season peaks in both demand and energy.



	Demand	Energy
Average Low Demand Season Monthly Index	0.974	0.963
Average High Demand Season Monthly Index	1.065	1.052
Ratio of HD Average to LD Average	1.094	1.093
Max Monthly Index	1.074	1.066
Peak Month	Aug	Aug
Min Monthly Index	0.944	0.907
Min Month	Dec	Jan

Table 6-2 CCT Annual Demand and Energy Summary: 2004-2008

6.3 Western Region KSACS Customers

The Western Region network supplies several large industrial customers that are not considered Eskom Distribution customers but are managed by Eskom KSACS. Particularly, the largest industrial customers in the Western Region are Eskom KSACS customers. However, from a technical perspective, they are still supplied from the Western Region's network and therefore have an impact on the region's profile.

The 36 largest KSACS customers' points of delivery (from a Notified Maximum Demand perspective; certain customers have multiple points of delivery) were selected using the 'Customer Service Area' filter in the LPU details list. These KSACS customers' accounts' Summary data was used to compile their annual demand and energy profiles. These represent a mixture of customers that are in the industrial or rail industry. The industrial customers account for about 65% and 75% of the contribution towards the summated demand and energy respectively. The industrial customers are on a version of the Megaflex tariff while the rail customers are on a special tariff that is still TOU orientated.

From Figure 6-6, the lowest monthly index for energy is registered in February. However, closer inspection points to the load shedding effects of 2008 that has resulted in a lower average energy monthly index.

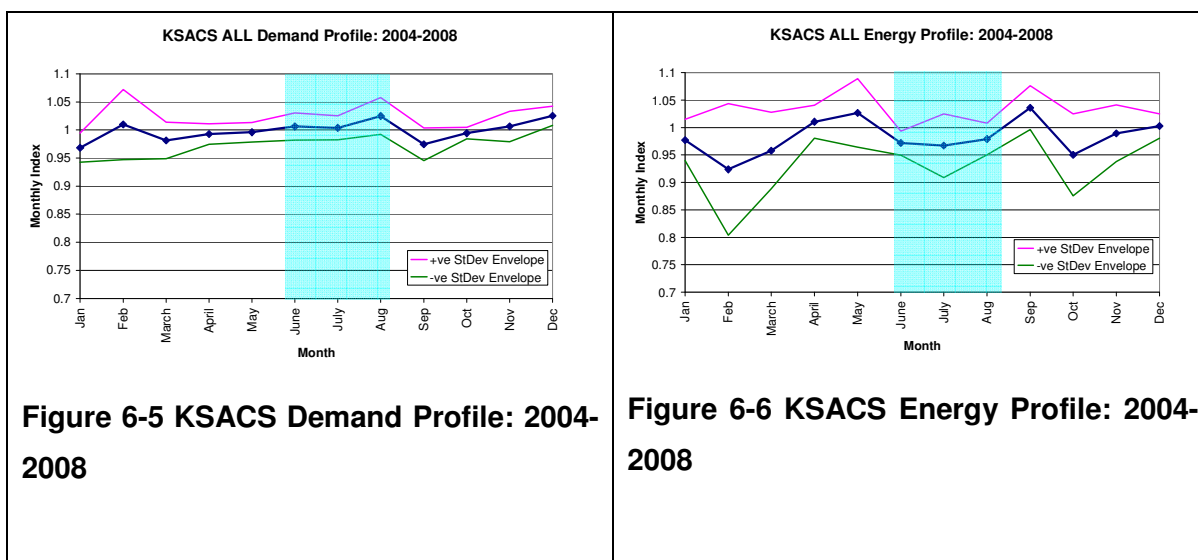


Figure 6-6 KSACS Energy Profile: 2004-2008

2008

	Demand	Energy
Average Low Demand Season Monthly Index	0.994	0.986
Average High Demand Season Monthly Index	1.017	0.973
Ratio of HD Average to LD Average	1.017	0.986
Max Monthly Index	1.025	1.036
Peak Month	Dec	Sep
Min Monthly Index	0.968	0.924
Min Month	Jan	Feb

Table 6-3 KSACS Annual Demand and Energy Summary: 2004-2008

Even though the Average High Demand Season Monthly Index for Energy is lower (only *marginally*), the Average High Demand Season Monthly Index for Demand is considerably higher (in relation to the same ratio for Energy). It is noted that the Average Low Demand Season Monthly Index for Energy would be higher if the abnormally lower February month value were not included. The Max Monthly Index for Demand occurs during the Low Demand Season; however, Network Demand Charges are not seasonal (on the Megaflex tariffs) and is consistent for the year. Therefore, a correlation is not possible between reduced values for average demand and higher charges, but a correlation is seen with reduced average energy consumption and higher charges.

The 3 largest customers (with 5 points of delivery) contribute more than 60% and 70% to this groups' demand and energy profiles respectively. To ensure that their specific influence does not overly skew the characteristics of this group's profiles, they are considered separately. When the 3 largest customers are removed from this list, the profiles have different shapes as shown in Figure 6-7 and Figure 6-8. This sample represents 89% of the total NMD of the balance of the KSACS customers.

From an annual demand perspective, these KSACS customers (without the largest 3) are not peaking in the High Demand Season but the average values for the High Demand Season are higher. Note that of this new group, the sample of 31 largest customers' points of delivery within this group, represent 87.5% of the NMD for this group and hence represents a significant proportion of this group. There is a negligible difference from an average monthly energy index perspective between the different seasons.

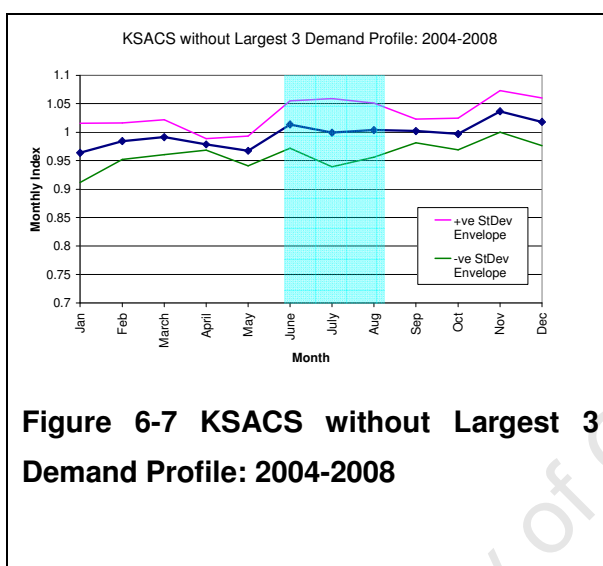


Figure 6-7 KSACS without Largest 3 Demand Profile: 2004-2008

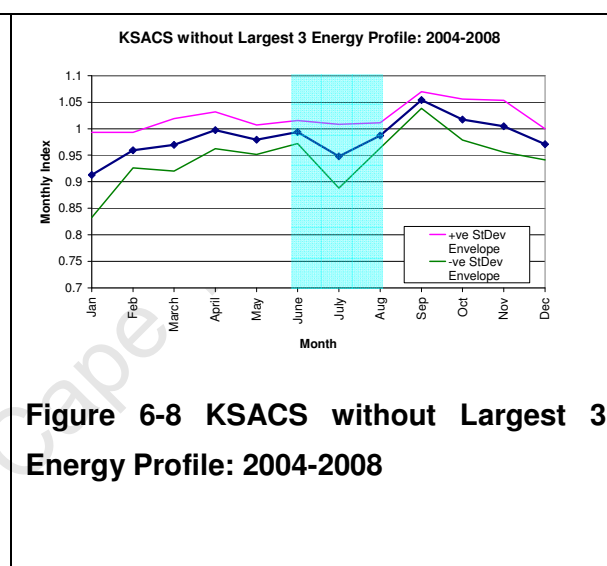


Figure 6-8 KSACS without Largest 3 Energy Profile: 2004-2008

	Demand	Energy
Average Low Demand Season Monthly Index	0.993	0.985
Average High Demand Season Monthly Index	1.005	0.976
Ratio of HD Average to LD Average	1.012	0.991
Max Monthly Index	1.036	1.054
Peak Month	Nov	Sep
Min Monthly Index	0.963	0.913
Min Month	Jan	Jan

Table 6-4 KSACS without Largest 3 Annual Demand and Energy Summary: 2004-2008

When one considers the 3 largest KSACS customers in Figure 6-9, Figure 6-10 and Table 6-5, a correlation is apparent between the higher Average Low Demand Season Monthly Index for Energy and reduced charges.

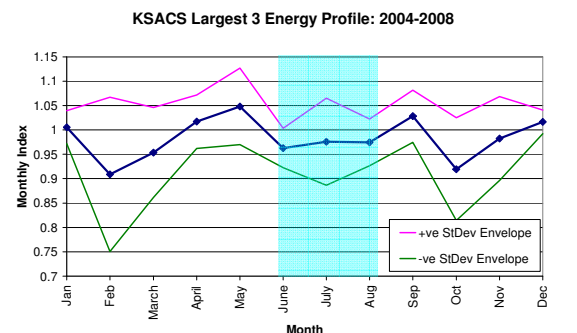
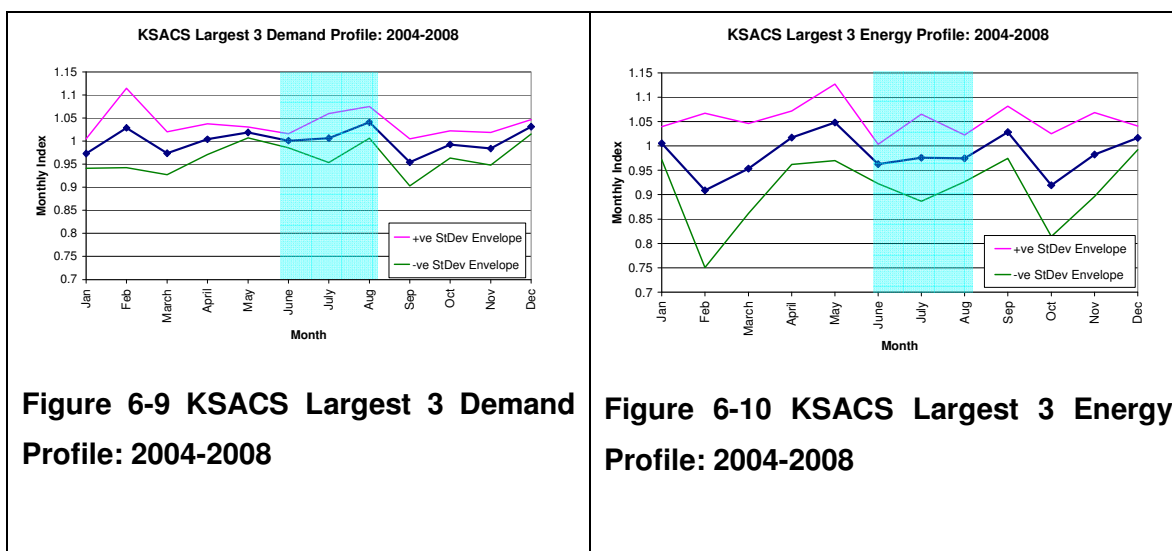


Figure 6-9 KSACS Largest 3 Demand Profile: 2004-2008

Figure 6-10 KSACS Largest 3 Energy Profile: 2004-2008

As Network Demand Charges are not seasonal differentiated, a correlation is not possible between the average values for demand for the different seasons. Note that overall shape of this profile is very similar to the shape of the profile for all KSACS customers. This further supports the reasoning to remove the largest 3 KSACS customers from the KSACS customer pool to ensure that readings are not overly influenced by a select few customers. The total KSACS customer group will now be segmented accordingly from this point forward.

	Demand	Energy
Average Low Demand Season Monthly Index	0.996	0.987
Average High Demand Season Monthly Index	1.016	0.971
Ratio of HD Average to LD Average	1.021	0.984
Max Monthly Index	1.041	1.048
Peak Month	Aug	May
Min Monthly Index	0.954	0.909
Min Month	Sep	Feb

Table 6-5 KSACS Largest 3 Annual Demand and Energy Summary: 2004-2008

6.4 Typical Non-Agricultural profile

The sample of customers was selected with the following criteria:

- Non-municipal by ensuring that the name does not include a municipal-type description.
- There is no CCT-type description like 'Cape Town' in the name.
- The tariff does not include any rural association like Ruraflex.
- Non-KSACS.

This sample of thirty customers represents the largest customers in this pool with complete data over the study period. They represent 49.5% of the NMD of Non-Agricultural (as well as Non-municipal) LPU customers. This sample of customers is

either on a Megaflex or Miniflex tariff (both have no seasonal Network Demand Charge differentiation with Miniflex having none at all). Their profiles are summarised in Figure 6-11, Figure 6-12 and Table 6-6.

Energy consumption seems to be more consistent across the year with the expected fall off in the December January holiday period when large parts of industry scale down their operations or close down completely.

There does not appear to be a correlation between the timing of Non-agricultural customers' annual peak demand and energy profiles and the region's annual peak demand and energy profiles respectively. Average seasonal monthly indices for Energy indicate a marginal preference for the expensive High Demand Season. Thus no correlation is apparent between higher energy charges during the High Demand Season and reduced energy indices.

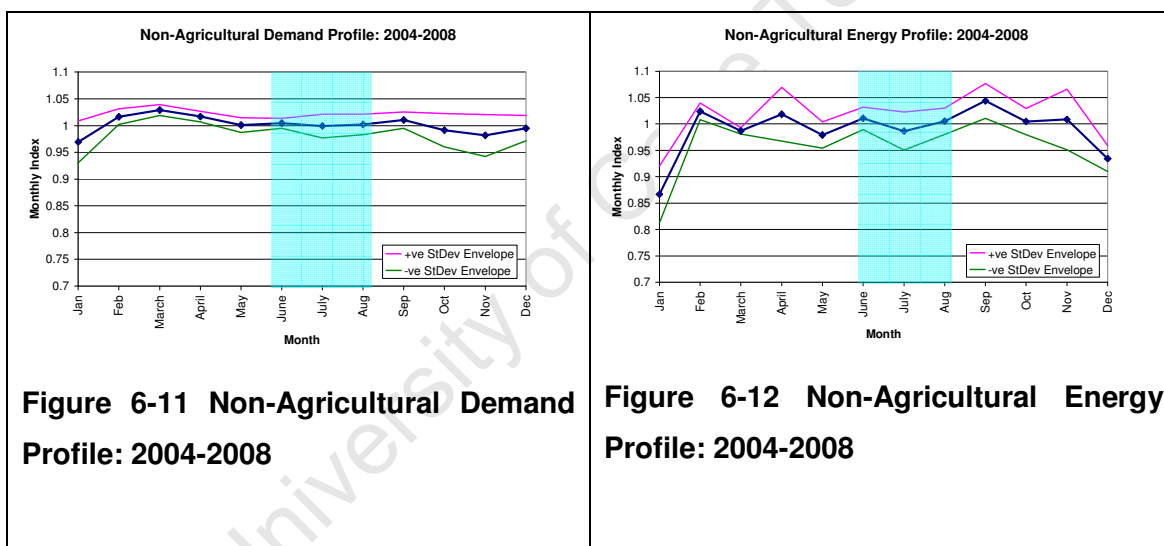


Figure 6-11 Non-Agricultural Demand Profile: 2004-2008

Figure 6-12 Non-Agricultural Energy Profile: 2004-2008

	Demand	Energy
Average Low Demand Season Monthly Index	1.001	0.985
Average High Demand Season Monthly Index	1.002	1.001
Ratio of HD Average to LD Average	1.001	1.016
Max Monthly Index	1.029	1.044
Peak Month	March	Sep
Min Monthly Index	0.969	0.867
Min Month	Jan	Jan

Table 6-6 Non-Agricultural Annual Demand and Energy Summary: 2004-2008

It is noted that the Average Low Demand Season Monthly Index is affected by considerably lower December, January and February indices. December and January are the traditional annual holiday months while February may have been

affected by the load shedding of 2008. When these months are removed from the calculation, the Average Low Demand Season Monthly Index is the higher value.

As the 30 largest customers in this group represent 49.5% of the total group, a more random sample of 30 LPUs are considered as a comparison. This randomly selected group represents 2.5% of the total NMD of the group. At least half of these customers are on the a version of the Nightsave tariff that does have a seasonally differentiated demand charge while the other customers are on versions of the Miniflex tariff.

The results are summarised in Figure 6-13, Figure 6-14 and Table 6-7. Despite the appearance of a difference in shape between the largest 30 and a random sample, similar conclusions can be drawn: There does not appear to be a correlation between the timing of Random Non-agricultural customers' annual peak demand and energy profiles and the region's annual peak demand and energy profiles respectively.

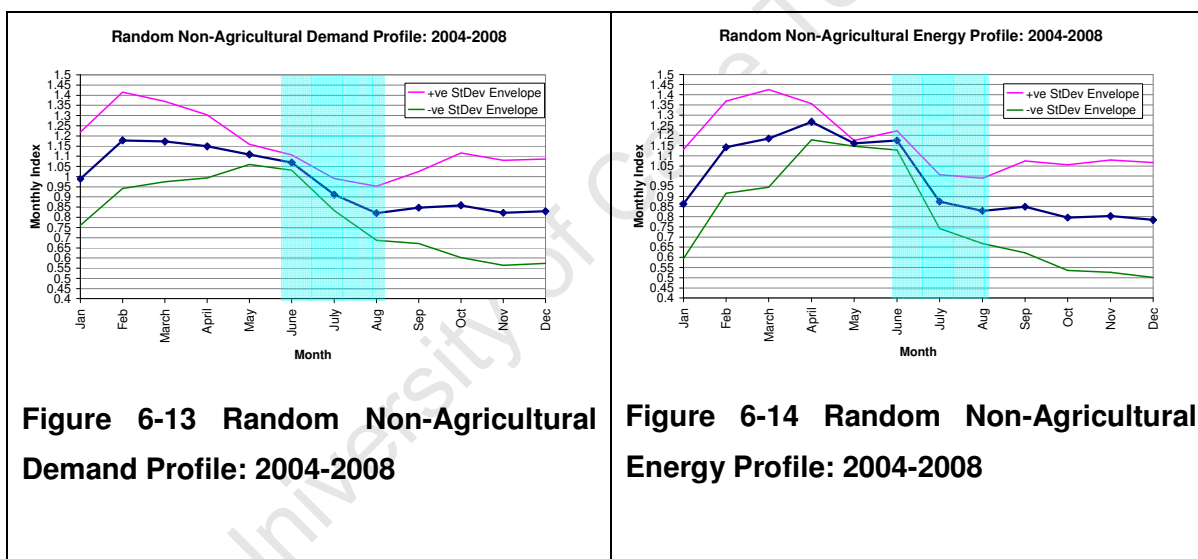


Figure 6-13 Random Non-Agricultural Demand Profile: 2004-2008

Figure 6-14 Random Non-Agricultural Energy Profile: 2004-2008

	Demand	Energy
Average Low Demand Season Monthly Index	0.995	0.983
Average High Demand Season Monthly Index	0.934	0.959
Ratio of HD Average to LD Average	0.939	0.976
Max Monthly Index	1.178	1.267
Peak Month	Feb	April
Min Monthly Index	0.820	0.784
Min Month	Aug	Dec

Table 6-7 Random Non-Agricultural Annual Demand and Energy Summary: 2004-2008

There is a correlation between the higher demand and energy charges of the High Demand Season and reduced average monthly indices. However, these indices do

not increase after the High Demand Season when demand and energy charges are again reduced.

In addition, the Standard Deviation window for the Random Non-Agricultural appears much bigger. This implies a greater inconsistency for the monthly values over the years being considered.

Note the similarity between the Random Non-Agricultural profiles and the random Larger LPU profiles in Chapter Five.

6.5 Non Municipal rural supplies

The sample of customers was selected with the following criteria:

- Non-municipal by ensuring that the name does not include a municipal-type description.
- There is no CCT-type description like 'Cape Town' in the name.
- Non-KSACS affiliation.
- The tariff includes a rural affiliation like Ruraflex.

The 30 largest Rural non-municipal accounts' Summary data was used to compile their annual demand and energy profiles. The majority of these customers are on a Ruraflex tariff which does have a seasonally differentiated energy charge. There is no seasonally differentiated demand charge. These thirty customers represent the thirty largest rural supplies on some form of the Ruraflex tariff with complete data and represent 8.4% of the total agricultural NMD on the Ruraflex tariff. These LPUs' results were summarised in Figure 6-15, Figure 6-16 and Table 6-8.

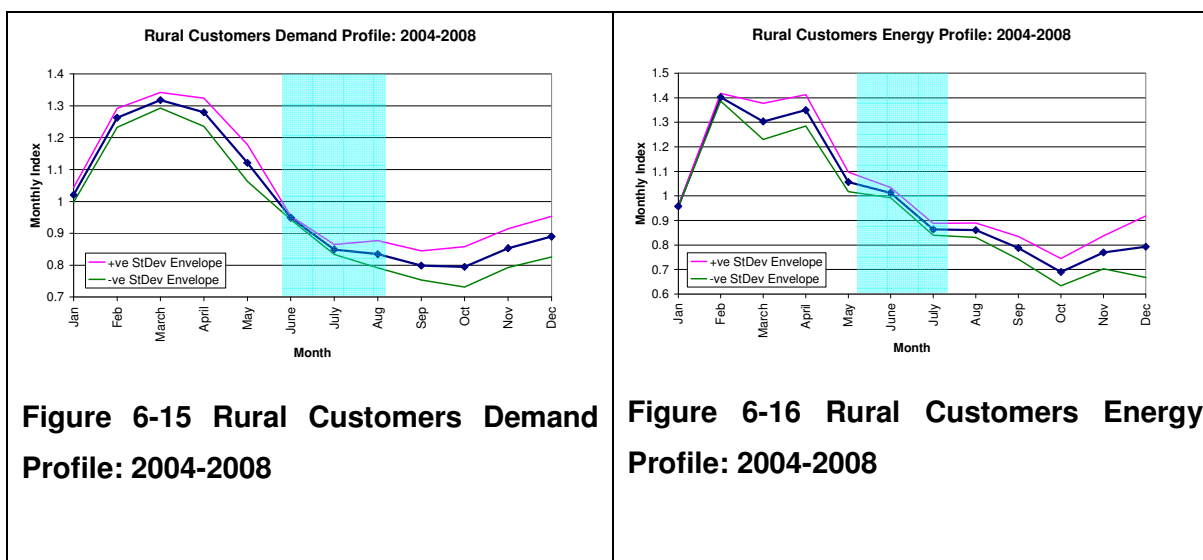


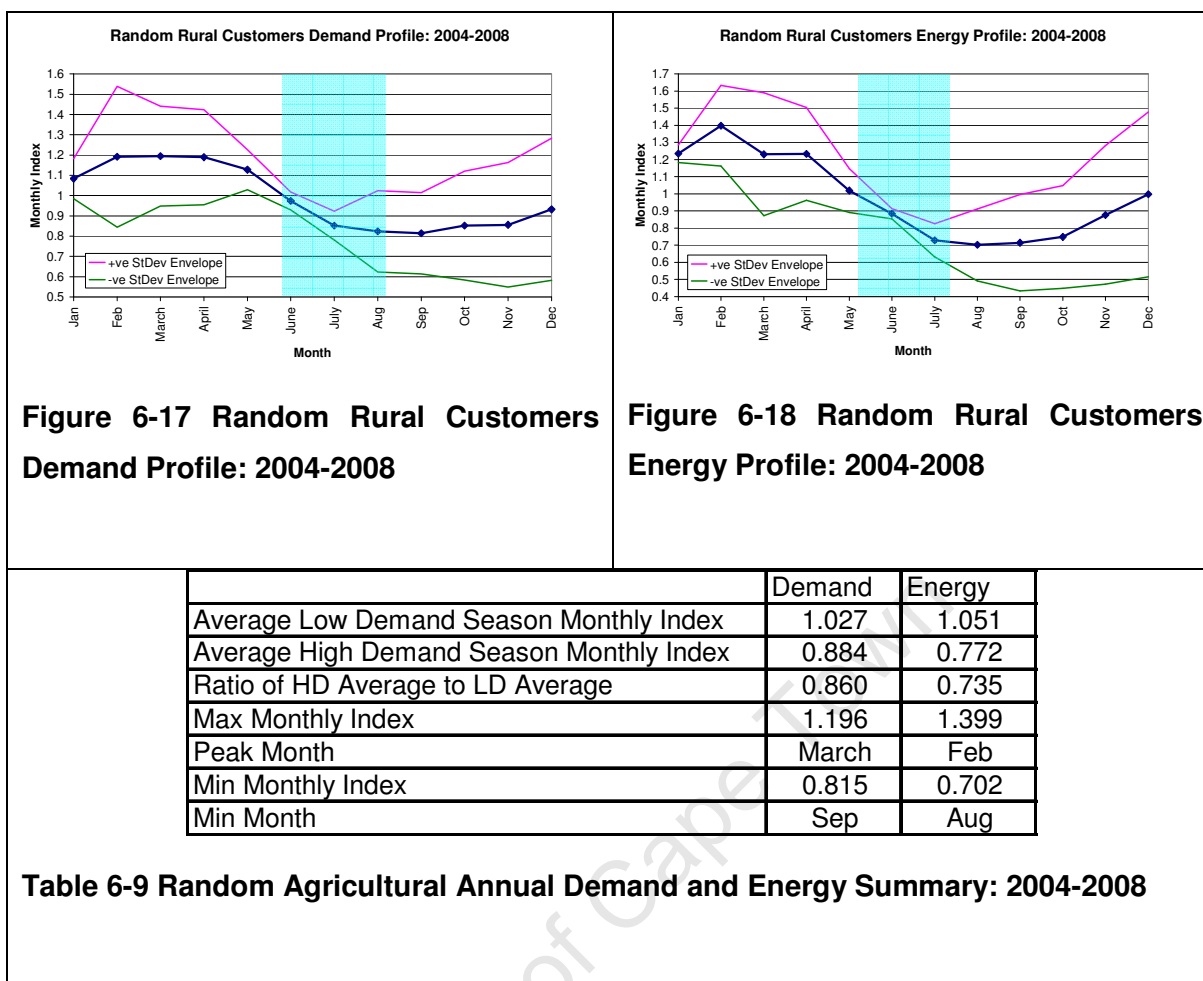
Figure 6-15 Rural Customers Demand Profile: 2004-2008

Figure 6-16 Rural Customers Energy Profile: 2004-2008

	Demand	Energy
Average Low Demand Season Monthly Index	1.038	1.012
Average High Demand Season Monthly Index	0.877	0.912
Ratio of HD Average to LD Average	0.846	0.901
Max Monthly Index	1.318	1.402
Peak Month	March	Feb
Min Monthly Index	0.795	0.689
Min Month	Oct	Oct

Table 6-8 Agricultural Annual Demand and Energy Summary: 2004-2008

As a comparison a random sample of 30 non-municipal rural supplies' results – effectively Agricultural LPU's - are summarised in Figure 6-17, Figure 6-18 and Table 6-9. Despite the wider Standard Deviation window, the overall profiles are very similar. Hence, the 30 largest Agricultural LPU's can be used a representative sample.



As is evident from Table 6-8 rural non-municipal customers register a peak outside the High Demand Season from a demand and energy perspective. There does not appear to be a correlation between the timing of Agricultural customers' annual peak demand and the region's annual peak demand. From an energy perspective, there appears to be a correlation between reduced energy consumption and higher energy costs during the High Demand Season.

Harvesting tends to happen towards the end of January and beginning of February. As these produce tend to remain in refrigeration until generally the beginning of April when it has to be prepared for the export and local markets, the LF for refrigeration demand is relatively high. As the refrigeration demand tends to be a high proportion of the agricultural load, it implies higher energy and demand monthly indices. Demand and energy decreases thereafter as activities are scaled down inline with the 'non-harvesting' season. Activities tend to resume from October onwards as preparations for the next harvest season commences.

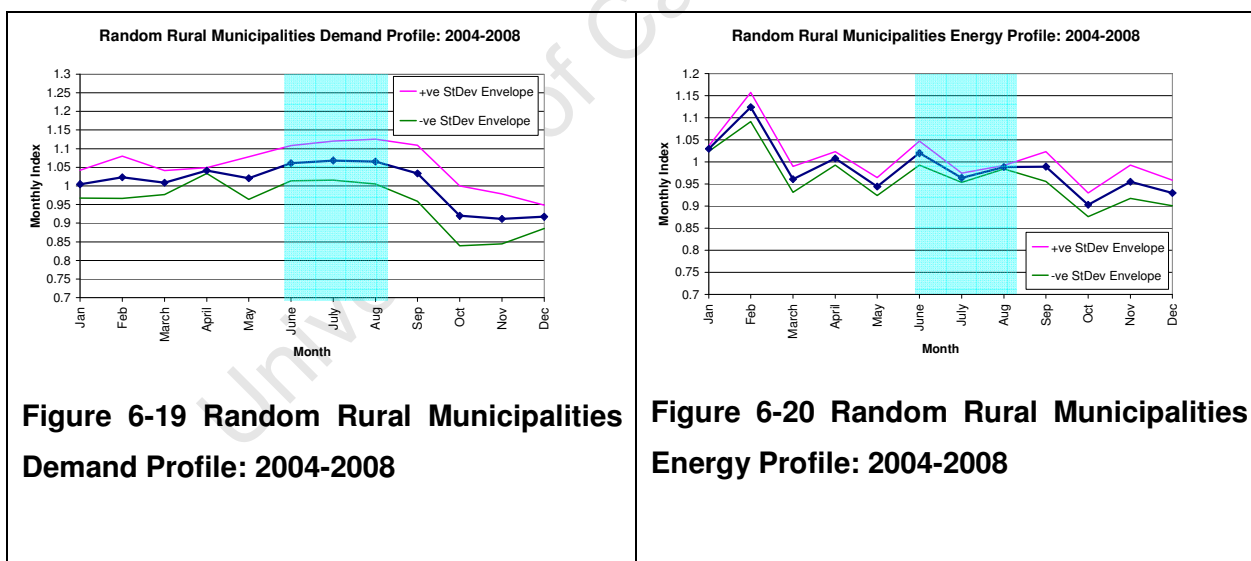
Therefore, this group of customers' profiles is more likely related to the harvest season as opposed to any seasonally differentiated component of the electricity tariffs.

6.6 Rural Municipality component

The sample of customers was selected with the following criteria:

- Municipal by ensuring that the name does include a municipal-type description.
- There is no CCT-type description like 'Cape Town'.
- The 32 largest Rural Municipalities' accounts' Summary data was used to compile their annual demand and energy profiles. The majority of these customers are on a Megaflex tariff and represent 63.6% of the total NMD of the Rural Municipalities' metering points in the region.

The random sample of 30 Rural Municipal LPUs represents 7.6% of the total NMD of the Rural Municipalities' results are summarised in Figure 6-19, Figure 6-20 and Table 6-10.



	Demand	Energy
Average Low Demand Season Monthly Index	0.987	0.983
Average High Demand Season Monthly Index	1.065	0.991
Ratio of HD Average to LD Average	1.079	1.008
Max Monthly Index	1.068	1.124
Peak Month	July	Feb
Min Monthly Index	0.912	0.903
Min Month	Nov	Oct

Table 6-10 Random Rural Municipalities Annual Demand and Energy Summary: 2004-2008

Despite the wider Standard Deviation window, the overall profiles are very similar with both groups having a demand peak during the High Demand Season. However, both samples indicate a February Energy peak. Several of the rural towns included in the study are coastal and typical holiday towns. This means that the areas would typically also show an increase in energy during holiday periods, viz December January holiday season and Easter Weekend. Some of the smaller municipalities would very likely be more of a holiday town rather than cater for the agricultural industry. This could explain the higher January energy value for the Random Rural Municipalities which would more likely include a smaller municipality. In addition, the February energy peak coincides with the Rural customers who are most likely in the agricultural industry. This implies that agricultural customers may have a considerable influence over rural municipalities' energy consumption profiles.

Hence, the 32 largest Rural Municipal LPUs can be considered significant enough to be a representative sample. From Figure 6-21, Figure 6-22 and Table 6-11 it does not appear that these customers are able to make a noticeable change to their annual profile to benefit from the cheaper Low Demand Season rates. These customers' peak demand and energy usage occurs in the expensive High Demand Season. There appears to be a strong correlation between Rural Municipalities' annual peak demand and the region's annual peak demand.

There is an apparent secondary demand peak in February to April of each year. Similarly to the energy profiles, the Rural Municipalities' demand profile could be influenced by the agricultural sector.

There is no correlation between higher energy and demand charges and reduced averaged monthly indices during the High Demand Season.

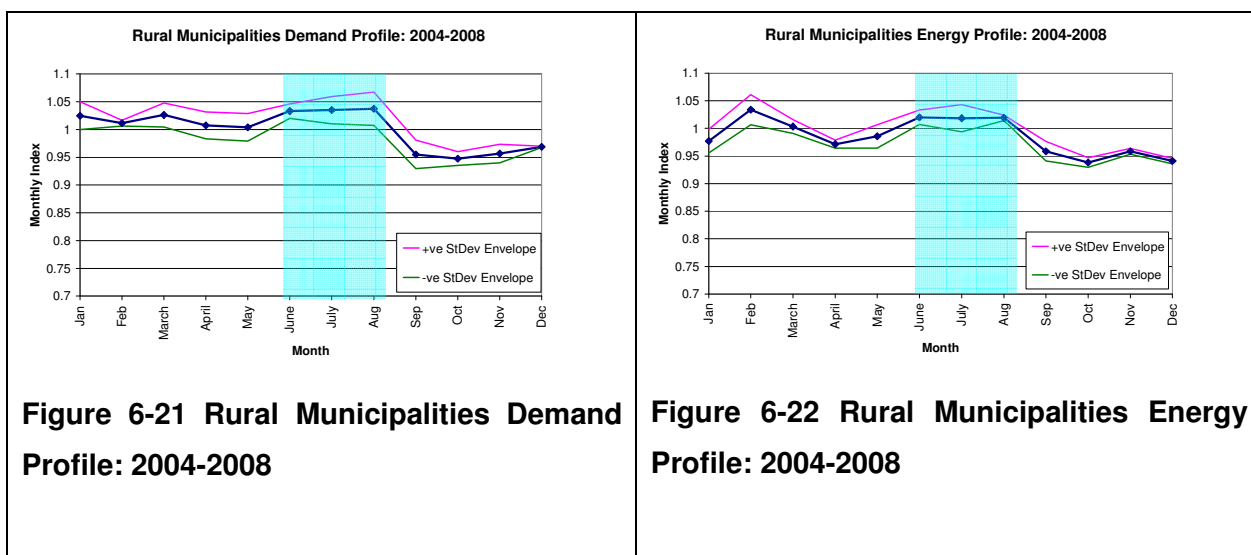


Figure 6-21 Rural Municipalities Demand Profile: 2004-2008

Figure 6-22 Rural Municipalities Energy Profile: 2004-2008

	Demand	Energy
Average Low Demand Season Monthly Index	0.989	0.974
Average High Demand Season Monthly Index	1.035	1.019
Ratio of HD Average to LD Average	1.047	1.046
Max Monthly Index	1.037	1.034
Peak Month	Aug	Feb
Min Monthly Index	0.947	0.938
Min Month	Oct	Oct

Table 6-11 Rural Municipalities Annual Demand and Energy Summary: 2004-2008

6.7 Residential component

The residential component can be broken down into 'normal' housing and Electrification housing. In an Eskom environment, the main difference between normal housing and Electrification housing is the presence of hot water cylinders in normal housing.

Broadly speaking, from an Eskom tariff perspective, normal housing would get at least a single phase 60A supply. Electrification housing would typically get a 10/20A single phase supply with 20A being more prevalent in the urban areas. 60A customers pay a higher energy rate than 10/20A customers in Eskom supply areas.

Electrification homes in the urban area use electricity mostly for cooking, lighting and media. Normal housing uses electricity for the same purposes but uses a larger proportion for water and space heating.

6.7.1 Residential Annual Demand

The residential market within Eskom supply areas can be divided, broadly, into 3 segments, viz. Electrification, Low Income and Middle Income.

Most residential customers in South Africa pay a flat tariff for their electrical energy needs. Regardless of time of day or time of year, the residential customer pays the same cost for a unit of electrical energy. There is no charge for demand and only energy consumption is metered. Hence the metering employed only needs to record the total energy usage but not when the energy was used. Due to the tariffs and associated metering system it is not possible to determine the demand and energy profiles for most individual residential customers.

Areas were chosen within the Western Region that typically represent the three different segments to ascertain the typical demand and energy profiles. Each area is supplied via an MV feeder that is metered with suitable metering at an Eskom Distribution substation. This metering has allowed the compilation of the Statistical metering database, which was used to describe the residential segment within Eskom Distribution, Western Region.

It should be noted that these profiles were for specific areas in the Western Region and have typically been in existence for at least 5-10 years. It is not a reflection of Electrification, Low Income or Middle Income households as a statistical whole. It was shown purely as a sample where the majority of customers in that area represent one of the residential segments and bulk metering data at Eskom substations is available to plot the specific profiles.

The Electrification area describes a residential area on the Cape Flats, Khayelitsha, about 30km outside of Cape Town along the N2 highway. This segment typically consists of 20A supplies where housing and services infrastructure are provided at no to minimal cost to customers by the government. The qualifying criteria for customers is that the household income should be less than R3,000 per month. Most of the houses are either government sponsored housing or informal dwellings with 20A supplies but mostly without hot water cylinders. According to Table 2 of NRS034-1:2007 [SANS, 2007], they would be considered Living Standard Measurement (LSM), groups 5 & 6 from a residential customer classification perspective (detail of table in Appendix).

The Low Income area describes a residential area on the Cape Flats, Belhar, about 25km outside of Cape Town along the N2 highway. This segment would consist of 60A supplies where customers contribute the majority to all of the costs incurred with respect to housing and services infrastructure (directly or indirectly). This type of housing market could be considered a typical *GAP Housing segment* where one of the qualifying criteria is that applicants should earn *between R7,200 and R10,000 per month*. *This sector of the population earns too much to qualify for subsidised housing (found in Electrification housing areas) and not enough to enter the private housing market* [Pollack, 2009]. This area is not considered *purely* GAP housing as it is still too new a housing philosophy within Eskom Supply areas within the Western Region with no existing GAP areas older than 5 years. However, the typical income in the area would fall within the prescribed criteria one would assume that the same type of person would be candidates for GAP housing. According to NRS034-1:2007, they would be considered LSM7 from a residential customer classification perspective.

The Middle Income area describes an area in the Blaauwberg area, about 25km outside of Cape Town along the West Coast. This segment would consist of 60A supplies where customers ultimately contribute (directly and indirectly) all the costs incurred with respect to housing and services infrastructure. The area would include some domestic three-phase supplies for the more affluent and often larger properties. According to NRS034-1:2007, they would be considered LSM7 & 8 from a residential customer classification perspective.

These individual areas, Khayelitsha, Belhar and Blaauwberg, are not homogenous from a customer type perspective but the majority of customers (at least 80%) would fall within the specific segment.

The respective demand and energy profiles for the different residential segments are shown in Figure 6-23 to Figure 6-28. It is clear that there is a strong correlation between all residential load types and the region's annual demand and energy profiles, including peaking during the High Demand Season.

The correlation between residential load and High Demand Season peaking can be extended to the reasons for the shape of the seasonal profiles of City of Cape Town and Rural Municipalities respectively. The bigger the residential component, the more likely the LPU is to peak during the High Demand Season.

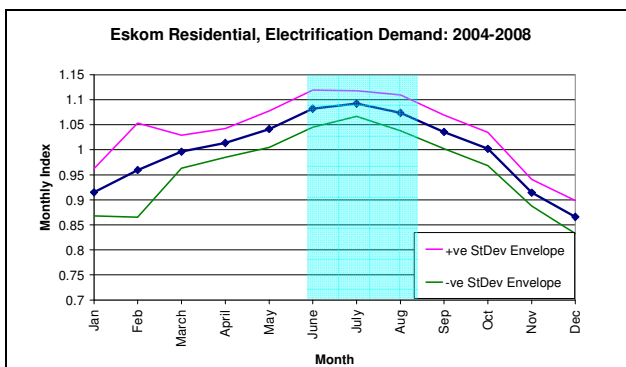


Figure 6-23 Eskom Residential, Electrification Demand Profile: 2004-2008

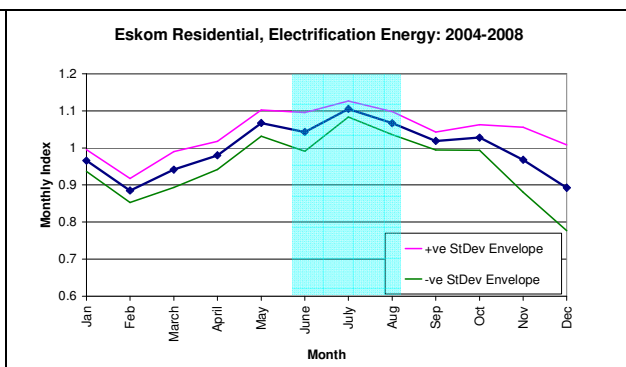


Figure 6-24 Eskom Residential, Electrification Energy Profile: 2004-2008

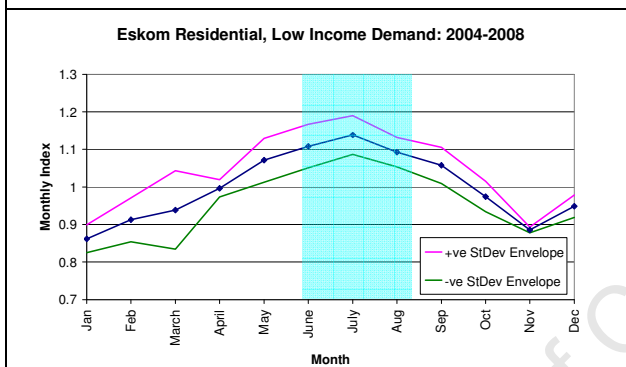


Figure 6-25 Eskom Residential, Low Income Demand Profile: 2004-2008

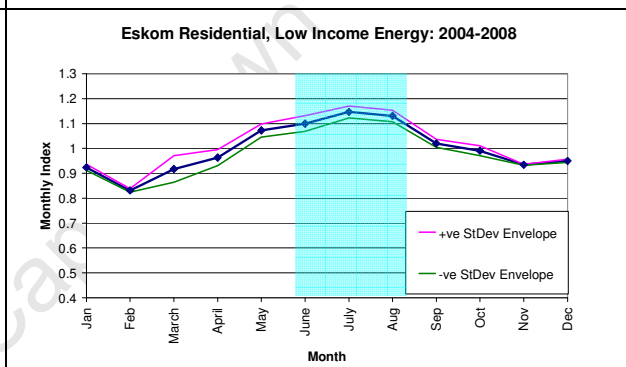


Figure 6-26 Eskom Residential, Low Income Energy Profile: 2004-2008

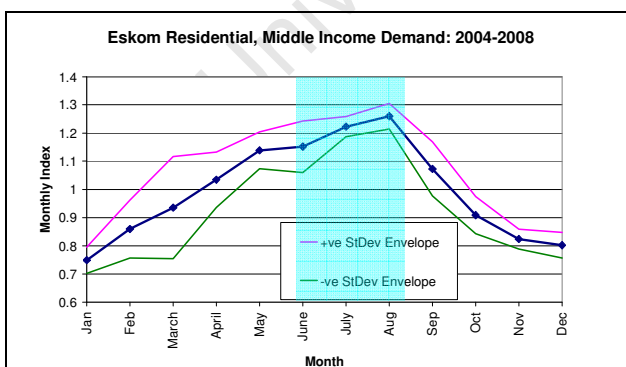


Figure 6-27 Eskom Residential, Middle Income Demand Profile: 2004-2008

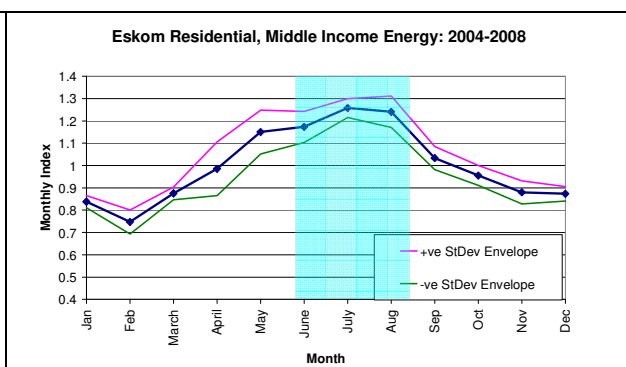


Figure 6-28 Eskom Residential, Middle Income Energy Profile: 2004-2008

Eskom’s residential segment can be summarised in Table 6-12.

	Electrification		Low Income		Middle Income	
	Demand	Energy	Demand	Energy	Demand	Energy
Average Low Demand Season Monthly Index	0.971	0.972	0.961	0.956	0.925	0.927
Average High Demand Season Monthly Index	1.082	1.072	1.113	1.126	1.211	1.224
Ratio of HD Average to LD Average	1.114	1.103	1.159	1.178	1.310	1.321
Max Monthly Index	1.092	1.105	1.138	1.147	1.260	1.258
Peak Month	July	July	July	July	Aug	July
Min Monthly Index	0.866	0.885	0.862	0.831	0.749	0.747
Min Month	Dec	Feb	Jan	Feb	Jan	Feb

Table 6-12 Eskom Residential Customer Annual Profile Summary

6.8 Western Region's Annual load factor analysis

Regionally, due to data availability the load factor can only be determined from 2002 onwards. To ensure an equivalent comparison, data for the region has been aligned to dates as per Eskom Annual Reports – e.g. the 2009 Eskom Annual Report will show a value for 2009 but it actually represents the period 1 April 2008 to 31 March 2009 performance. Results of comparative load factors are shown in Figure 6-29.

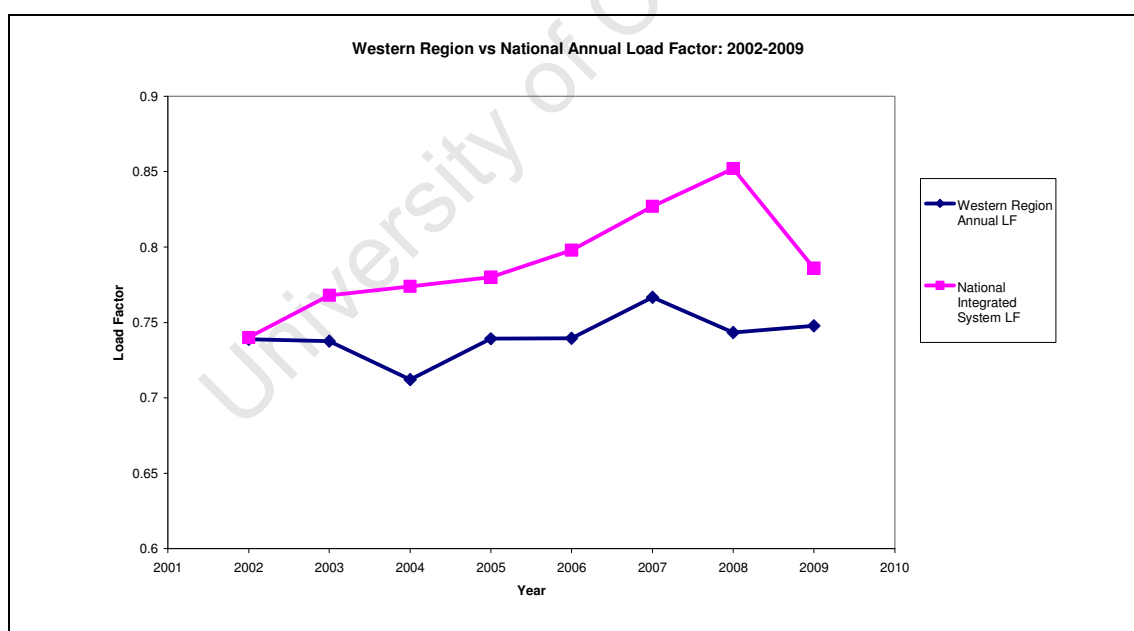


Figure 6-29 Western Region vs National Annual Load Factor: 2002-2009

Both graphs start at similar values of about 0.74. Thereafter, the national integrated load factor is increasingly higher than the regional graph. The regional graph also shows an upward trend but at a much slower rate. It is evident that the regional graph follows the national integrated system load factor in its upward direction between

2004 and 2007. However, for the other years the regional load factor seems to move in the opposite direction. The national graph peaks at a value of 0.85 in 2008 while the regional graph only peaks at 0.77 in 2007. It should be noted that while the country experienced load shedding during 2007 and 2008, the Western Region had similar experiences during 2006. Thus, differences between the Western Region and the National Integrated System could have been influenced by factors other than regional differences.

The differences are further illustrated in a basic statistical comparison in Table 6-13. It is evident that variation over the study period for the Western Region is very small relative to the National Integrated System value when one compares the standard deviation values (0.01 vs. 0.04 respectively). This implies that there has been much less change for the region vs. the country.

	Western Region	National Integrated System
Mean	0.74	0.79
StDev	0.01	0.04
Max	0.77	0.85
Min	0.71	0.74

Table 6-13 Western Region vs National Integrated System Load Factor comparison

6.9 Chapter Summary

LPUs only account for 1.1% of Eskom Western Region number of accounts but consume 89.6% of the energy and contribute 80.1% to the Western Region's revenue.

The equivalent values for residential customers are 92.5%, 6.7% and 13% respectively.

The 3 largest KSACS customers appear indifferent to the higher costs incurred during the High Demand Season.

KSACS customers (without the largest 3), Agricultural and Non-agricultural customers peak outside the High Demand Season. This does not necessarily imply

that they are all responding to the seasonal aspect of the pricing signals access to load profile records prior to the implementation of TOU tariffs not possible.

Agricultural customers' demand and energy profiles were largely dependant on the seasonality of their crops.

Annually, CCT, Eskom residential customers and Rural Municipalities peak during the High Demand Season. There is a strong correlation between the residential segment and these LPUs' profile, including a High Demand Season peak.

A comment is required with regard to LPU selection. The 30 largest LPUs per group were chosen and in several cases a significant proportion of the total NMD for that group is being represented. Where the significance is not as great, a random sample of the remainder of LPUs within that group was taken to illustrate any discrepancies. CCT, KSACS Large 3 and KSACS without Large 3 represent significant proportions of that particular group and would be considered representative of that group. It was found that the random sample for Agricultural and Rural Municipalities are very similar to the initial selection of at least 30 largest LPUs within that group despite the larger Standard Deviation window.

However, for Non-Agricultural LPUs, the random sample's profile is significantly different to warrant further comment. If a statistically representative sample of all the Non-Agricultural LPUs were taken, there would be a probability that some of the 30 largest Non-Agricultural LPUs would be included in that sample. As the 30 largest Non-Agricultural LPUs average NMD is 7340kVA while the sample of the remainder of 30 Random Non-Agricultural LPUs' average is 363kVA, it would be fair to say that the inclusion of one of largest Non-Agricultural LPUs in an all-inclusive sample would have a significant influence – to the point of dominating - over the random samples' profiles.

Therefore, in order to be consistent with the selection criteria of the other LPU groups, the 30 (at least) largest LPUs are chosen to represent a significant proportion of that group. The subsequent chapter will indicate the weekly profile for the different LPU groups that should highlight the potential daily response to TOU tariffs. The same LPUs that were selected to assess seasonal response are selected to assess daily response to TOU tariffs.

7. Western Region Analysis: Daily Demand

This chapter follows a similar format as Chapter 6. However, instead of annual demand, the daily demand profiles are discussed. The specific groups of LPUs was analysed to determine any correlation between LPU profiles and, firstly, the regional profile and the pricing signals from the different tariffs.

This chapter achieves the following:

1. The Western Region demand profile is analysed to determine the characteristics of the region.
2. Due to the strong correlation that exists between the residential customer and the region's annual profile, typical Eskom Residential customers' consumption profiles is analysed first to determine any correlation that might exist with the Western Region's overall demand profiles.
3. Each LPU customer group's weekly behaviour is analysed to determine a possible correlation to the Western Region's overall demand profiles. The same LPUs that were chosen for the different LPU groups' annual analysis is chosen for this analysis.

The data used to compile the Western Region's Annual profile in Chapter 6 indicated that the region's demand and energy peaked in 2008 during the month of July. In addition, the national system peaked during the same month. As TOU tariffs are designed to reduce the peak, this particular month will be studied to determine typical daily demand characteristics.

As for Annual demand, a similar Box-Jenkins technique was used to determine the profile for the Daily demand; however, instead of a 12-month moving average, a 336-half-hour (7 days) moving average for demand was compiled to determine the typical week-profile for July 2008. Four weeks of data was considered to determine a 336-half-hour moving average; however, as 1 July 2008 falls on a Tuesday and the need to consider four full weeks that start on a Monday (in order to describe the 'typical week'), data for 30 June was included as 'part of July'. The four weeks thus started on 30 June and end on 27 July.

The separate pricing periods of the day, viz. Off-peak, Standard and Peak is shown in clear, light grey and dark grey respectively.

A Load Duration Curve (LDC) is then plotted for the different LPU groups for the same period 30 June through 27 July 2008 for the individual TOU periods of the day show a quantitative comparison between the periods.

7.1 Western Region profile

As the Western Region's profile is compiled as a result of readings at different Transmission substations, data is not available in the same format as presented by MV90 for LPUs and Distribution substations. Data provided by Eskom's local Energy Trading department only provides hourly readings. However, the same philosophy will be applied to produce a similar type plot as for LPUs and the residential segments.

If one considers the typical week profile during the month of July 2008 for the region in Figure 7-1, the following characteristics are evident:

- From Monday to Thursday, the region tends to peak during the evening Peak period at 19h00. These profiles, specifically, correlate strongly with the Typical winter's day profile (Figure 7-2). Note that national profile also indicates an annual peak during July.
- The Fridays of this month shows equivalent peaks during both morning- and evening Peak periods.

07h00 reading is about 83% of evening peak reading while the morning peak occurs consistently from Monday to Friday at 11h00 at about 95% of weekday peak value. Figure 7-2 shows the Typical winter day morning peak at about 09h00 while the Peak day 14 July 2008 indicates an 11h00 morning peak.

- On Saturdays, the region tends to peak during the Standard periods but at values less than weekday peaks. Saturdays present the lowest daily peak values.
- Sunday peak is about 91% of the weekday peak value at 20h00.
- Weekday minimum is at about 62% of weekday peak value. Note that this value excludes Monday as the early hours of this day could be considered similar to the weekend from a social and subsequent load perspective.
- LF for study period is 81% (based on the typical week in July 2008).

The description for the Western Region profile can be summarised in Table 7-1. This description (along with Figure 7-1 and the Load Duration Curve in Figure 7-3 with its associated summary in Table 7-2) will be used in subsequent descriptions of all other profiles.

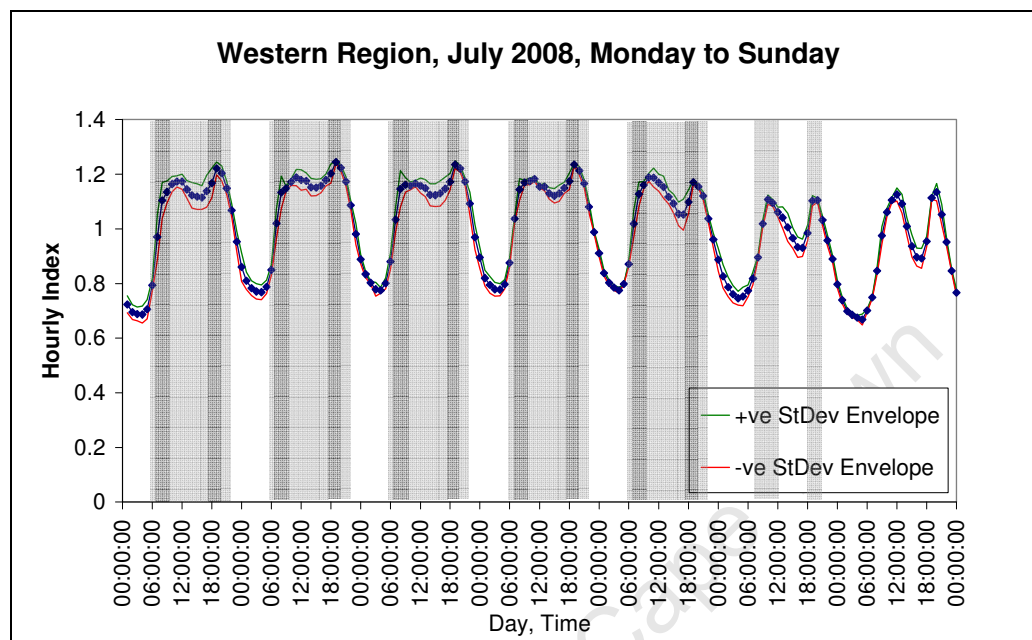


Figure 7-1 Western Region typical week demand profile [Eskom, 2009a]

It is evident (from Table 7-2 and Figure 7-3) that the highest maximum value for the different periods is for the Peak period; this coincides with the highest average value also being registered for the same period. The lowest maximum and average values are registered for the Off-peak period. This indicates that the pricing signal illustrated by the highest cost of the most expensive period does not appear to be discouraging the region as a whole to move its maximum demand from the Peak period.

It is worth repeating that the morning peak for the region for the month of July 2008 occurs at 11h00 during the Standard period while the morning Peak period ranges from 07h00-10h00. This coincides with the national morning peak for the Peak Day 14 July 2008 in Figure 7-2 but not with the Typical winter day. The minimum values for the Standard and Peak periods occurred at 06h00 and 07h00 respectively on Mondays.

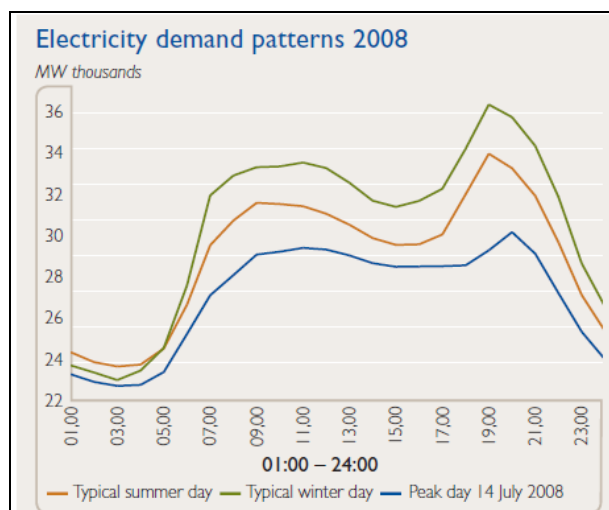


Figure 7-2 Electricity demand patterns 2008 [Eskom, 2009e]⁵

Weekday peak index	1.245
Weekday peak incidence	19h00
07h00 index to weekday peak ratio	83%
Weekday morning peak incidence	11h00
Weekday morning peak to weekday peak ratio	95%
Weekday min incidence	04h00
Weekday min to Weekday peak ratio	62%
Sunday peak incidence	20h00
Sunday peak index to weekday peak ratio	91%
LF	81%

Table 7-1 Western Region Weekly profile Summary

From Table 7-2 it is evident that the average and maximum values for the Standard period is about 98% of the equivalent Peak period values. This implies that a high LF is achieved during the workday week from 06h00 to 22h00.

⁵ It would appear that the legend may be incorrect. Correct legend should rather have green plot as *Peak day 14 July*, brown plot as *Typical winter day* and blue plot as *Typical summer day*.

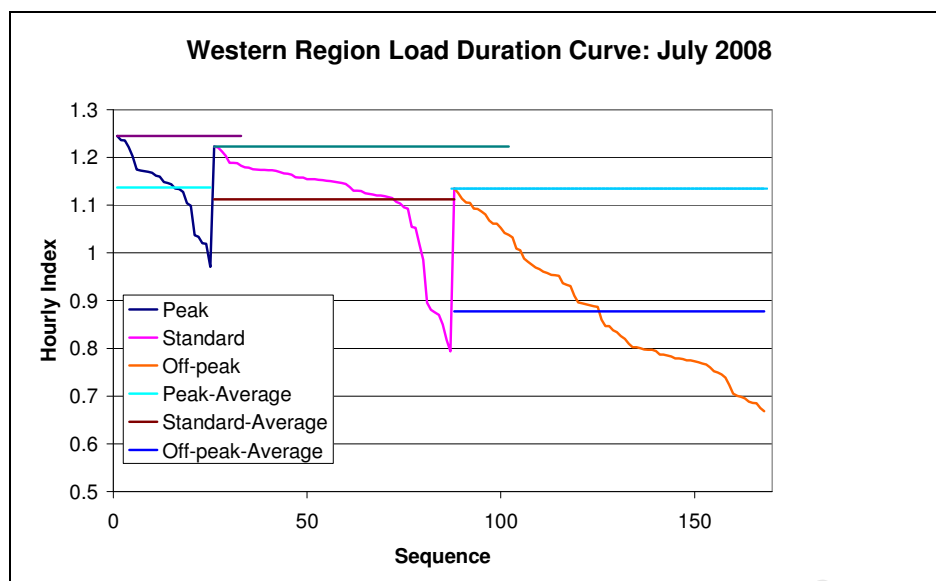


Figure 7-3 Western Region LDC: July 2008

	P	S	OP
Max of Hourly Index	1.245	1.223	1.135
Average of Hourly Index	1.137	1.112	0.877
Min of Half-hourly Index	0.970	0.794	0.668

Table 7-2 Western Region LDC Summary

7.2 Residential Daily Demand

As per Annual Demand Analysis, the same residential segments (and associated geographic areas) were studied, viz Middle Income, Low Income and Electrification segments to illustrate the possible societal differences that determine an area's electricity consumption pattern. Results are summarised in Figure 7-4 to Figure 7-6 and Table 7-3.

It should be noted that the Weekday peak index is not a reflection of the ADMD in relation to the other residential groups. Instead, it should be viewed as a measure of the diversity of load during the week. This statement is supported when one considers that the Electrification segment has the highest Weekday peak index but the lowest LF in Table 7-3. This is also an indication that a high proportion of their energy usage occurs during the short Peak periods.

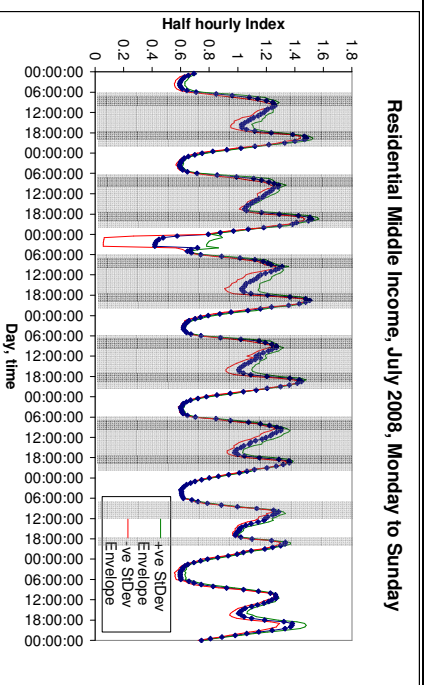


Figure 7-4 Residential Weekly Middle Income Demand Profile: July 2008

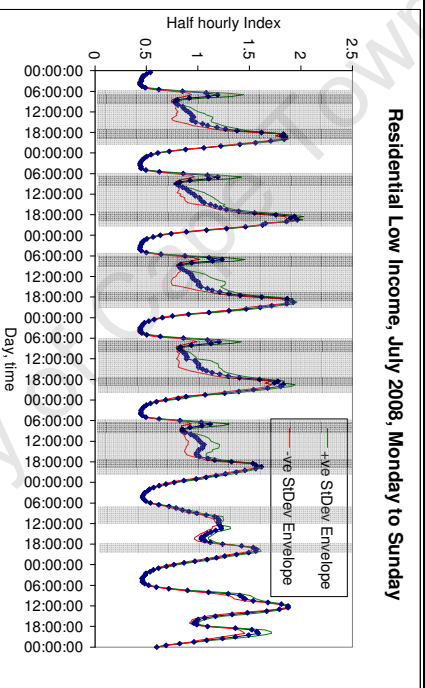


Figure 7-5 Residential Low Income Weekly Demand Profile: July 2008

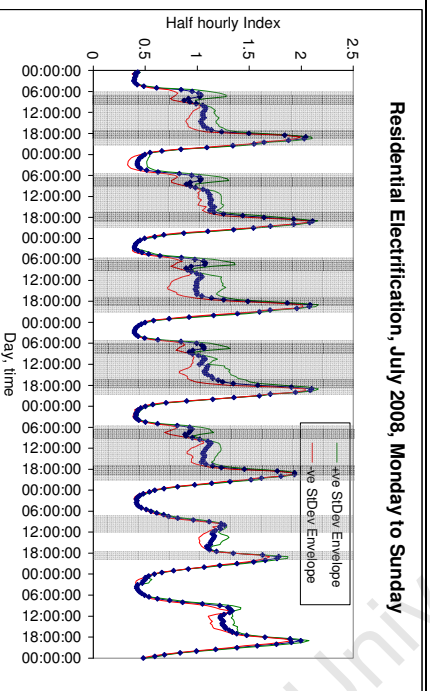


Figure 7-6 Residential Electrification Weekly Demand Profile: July 2008

	Middle Income	Low Income	Electrification
Weekday peak index	1.517	1.965	2.109
Weekday peak incidence	19h30	19h30	19h00
07h00 index to weekday peak ratio	67%	63%	50%
Weekday morning peak incidence	09h30	07h00	11h30
Weekday morning peak to weekday peak ratio	86%	63%	53%
Weekday min incidence	03h30	04h00	02h30
Weekday min to Weekday peak ratio	39%	22%	19%
Sunday peak incidence	19h00	12h00	19h00
Sunday peak index to weekday peak ratio	91%	95%	95%
LF	66%	51%	48%

Table 7-3 Western Region Weekly Residential Profile Summary

Further, it is noted for the Middle Income segment that the Weekday min to Weekday peak ratio is higher than indicated by the profile in Figure 7-4 on the third day, Wednesday. It was established that there was an outage in a portion the area for planned maintenance. This resulted in readings that were much less than it would have been during normal conditions. This is further supported when the large variation in standard deviation is considered for that particular morning. Therefore, that particular morning's data was not considered for the minimum of the weekday.

Interestingly, the Low Income residential group's Sunday peak is at 12h00 while the other segments point to an evening peak. Belhar is an area within the Western Region where the overwhelming majority of the people are *coloured*⁶ where Sunday lunches are considered the main meal for the week (typically after having spent the morning in church). Sunday dinner times are considered light meal times and hence the lesser half hourly index values for the evening in relation to lunch time values.

The Weekday peak incidence (19h00 to 19h30) for all residential customers appears to have a strong correlation to both the regional and national profiles, while there seems to be more diversity for the Weekday morning peak incidence (07h00 to 11h30). Only the Middle Income segment's morning peak incidence coincides with the equivalent regional weekday value.

When the LDCs are plotted for the differential residential segment (Figure 7-7 to Figure 7-9) there is strong correlation between the Middle Income segment and the regional LDC in terms of maximum and average values in terms of ranking between the periods.

⁶ A term that is used to refer to people in South Africa who have some African ancestry but not *enough* to be considered black in a South African context.

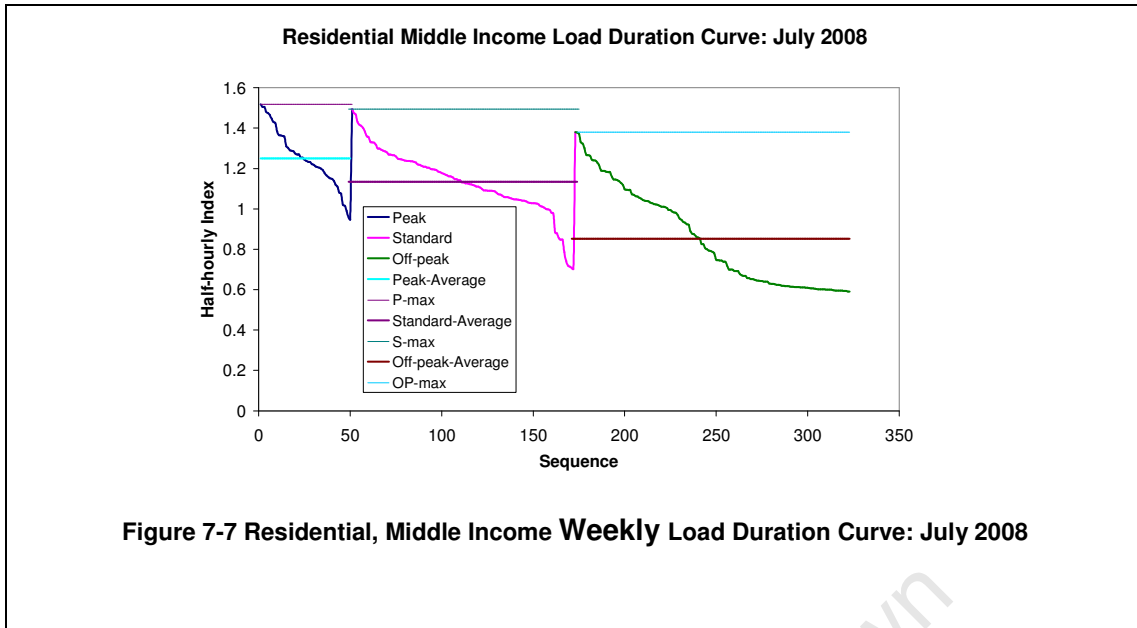


Figure 7-7 Residential, Middle Income Weekly Load Duration Curve: July 2008

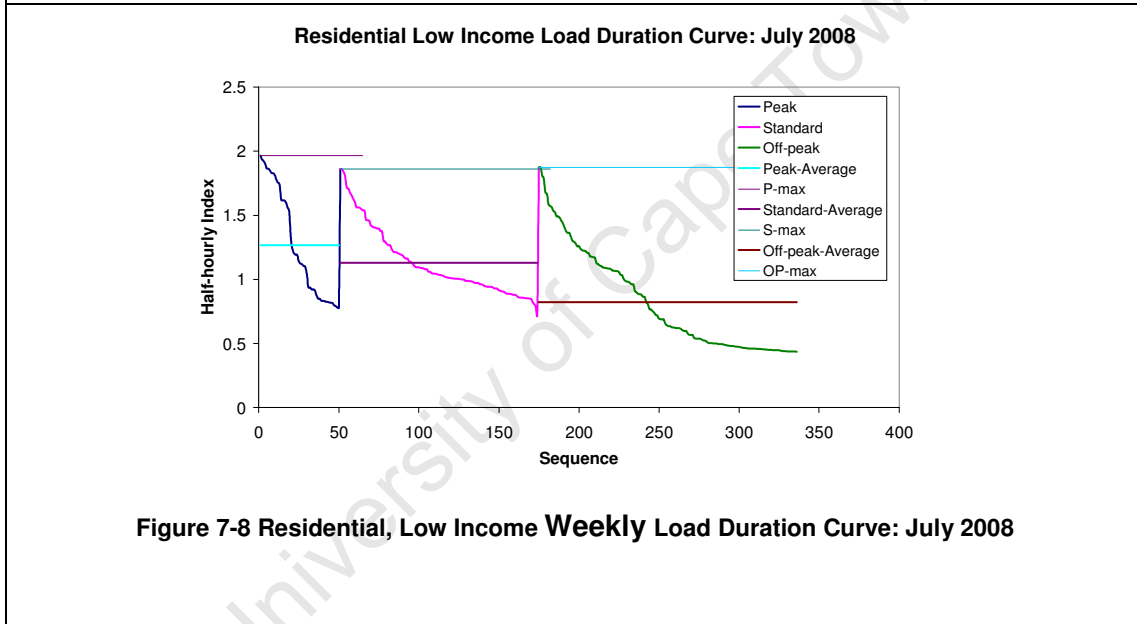


Figure 7-8 Residential, Low Income Weekly Load Duration Curve: July 2008

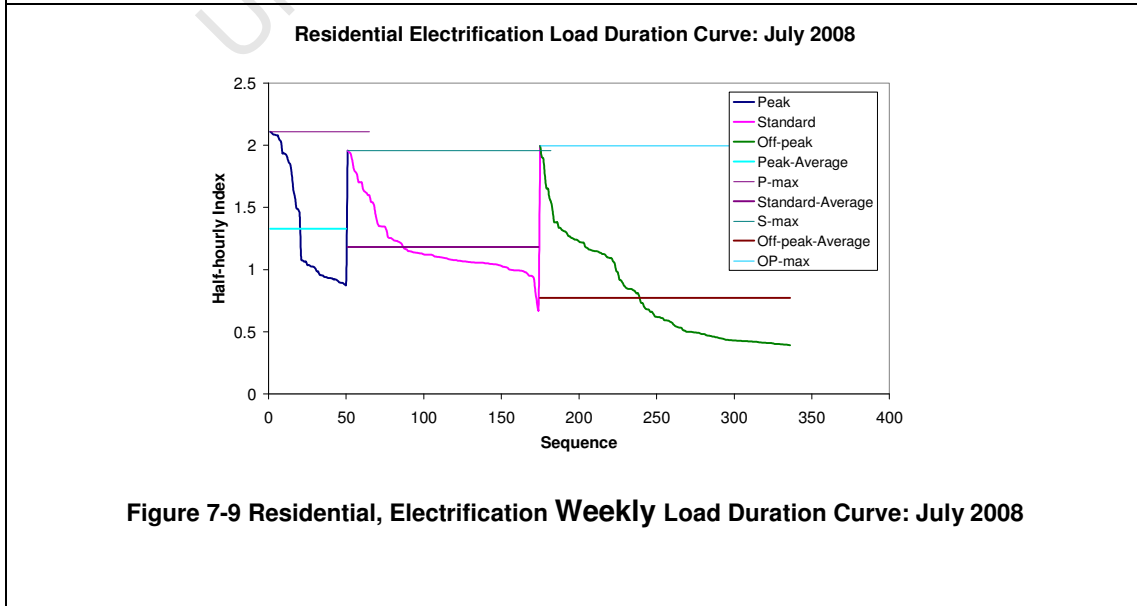


Figure 7-9 Residential, Electrification Weekly Load Duration Curve: July 2008

However, the Low Income and Electrification segment differ where the Off-peak maximum value exceeds the equivalent Standard period value.

It is evident from the Load Duration Curves that the maximum values for the different periods are relatively similar in value. This could be interpreted in a manner that suggests that even though the residential sector may have a significant influence over the LPU's overall annual demand profile, that the 'culprit' may not be as influential with respect to the daily profiles. However, note that the Peak period maximum values for all residential groups is at 19h00 which coincides with the regional and national peak demand incidence. Further, it should be noted that the max value for all the residential groups' Standard period is at 20h00 on a weeknight, immediately after the Peak period. The residential customer generally pays a flat daily tariff with no pricing signal to change its energy consumption habits. An appropriate pricing signal could change the times of these respective peaks by changing the shapes of the demand profiles in Figure 7-4 to Figure 7-6, thereby reducing peak demand. Faruqi et al. [2007a] noted in their paper, *The Power of 5 percent*, that *even a 5% drop in peak demand can yield substantial savings in generation, transmission and distribution costs*. Even though the residential segment do not contribute wholly to the demand during Peak periods, it is interesting that in a South African context, 5% could equate to about 1.8GW. This could mean that expensive peaking stations like OCGT would need to operate much less frequently.

The average values for the different periods could shed more light on this issue. The ratio of the Standard period Average to Peak period Average is 89% for Electrification and Low Income residential customers (compared to 91% for Middle Income customers). This presents an opportunity where energy could be shifted from Peak periods to other less expensive periods with an appropriate pricing signal.

All three residential segments registered the highest LF per period during the Peak period and the lowest during the Off-peak period. The Middle Income segment registered a LF of 82% for the Peak period with value of 64% and 63% being registered for the Low Income and Electrification segments respectively. The smaller LFs are most likely a result of the lack of load for these specific segments during the morning Peak period. This implies that the supply infrastructure should be available that can cater for these short evening Peak periods but *idles* (relatively) for the rest of the time. It should be noted that the supply infrastructure includes expensive generation like OCGT that is typically used to cater for the Peak periods, and that

transmission and distribution networks have to be available to transfer the power from the generation sites to the end customer during the Peak periods (but idles for the rest of the time).

As with the Annual Demand analysis where it was found that LPUs with significant residential load tend to display a residential influence (with High Demand Season annual peaks), it would be fair to expect that the residential segment could have a strong influence over those LPUs' daily profiles.

7.3 Western Region's largest customer, City of Cape Town

Figure 7-10 shows a typical week profile of the CCT at one of its major supply points from Eskom where it represents more than 50% of its overall demand. It is evident that the daily weekday profile is considerably flatter in comparison to the Western Region's overall demand profile for a day.

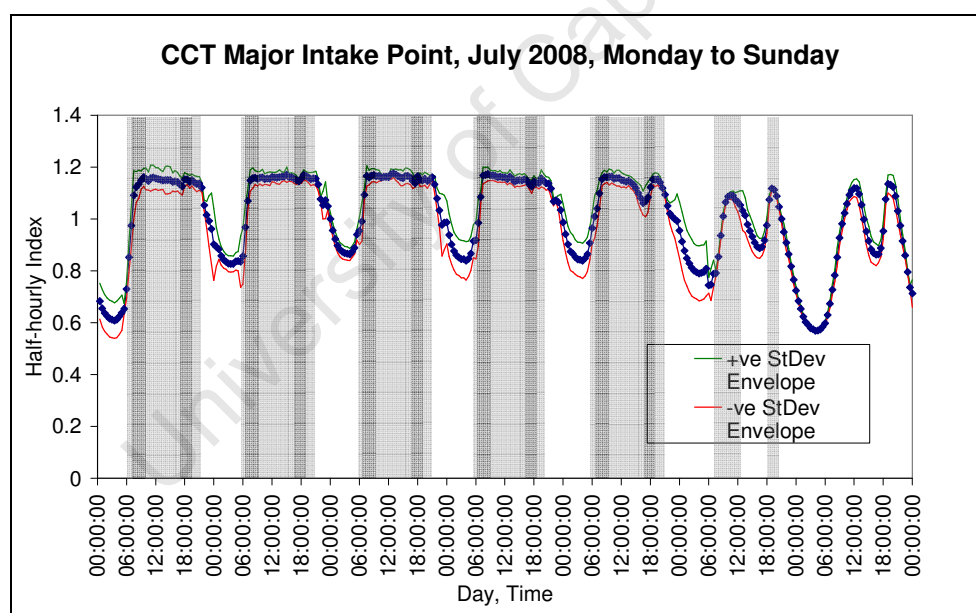


Figure 7-10 CCT Weekly Demand Profile at Major intake point [Eskom, 2009a]

As the particular point of supply being profiled above is metered at a Nightsave tariff option, it is in their favour to limit their peaks during the overall Standard and Peak times (of Miniflex, Megaflex and Ruraflex) on weekdays, i.e. from 06h00 to 22h00. This is achieved by using their pump storage scheme, as well as load management via a residential ripple control system to limit the expected evening peak. It is evident

that there is much more variation in demand during Off-peak periods as there is no demand charge for this period.

This is further illustrated when 35 of CCT’s largest LPU supply points are summated using MV90 data as shown in Figure 7-11, Figure 7-12 and Table 7-4. The summated load represents 97% of CCT’s diversified LPU load at the time of the study. CCT supplies the majority of residential customers in the Western Region. However, Table 7-4 shows that the morning peak appears on par with the evening peak – 99.6% ratio. The Standard period maximum value is also 99.6% of the equivalent Peak period value.

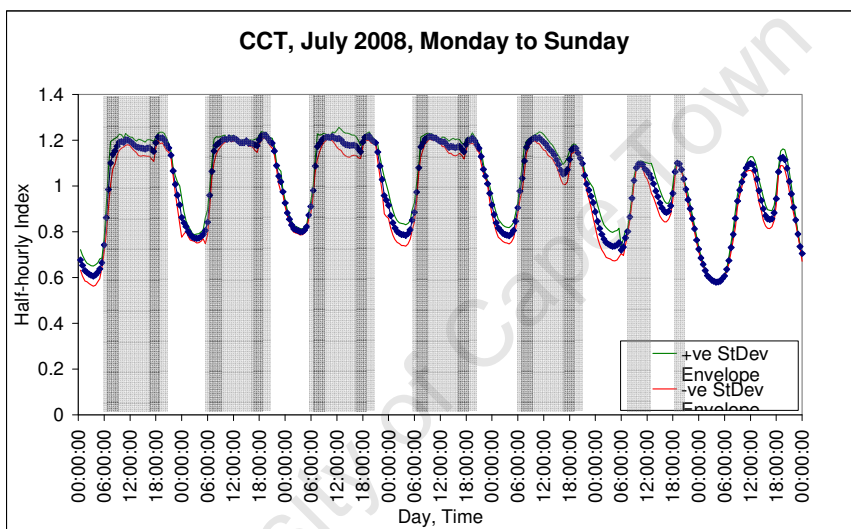


Figure 7-11 CCT Weekly Demand Profile: July 2008

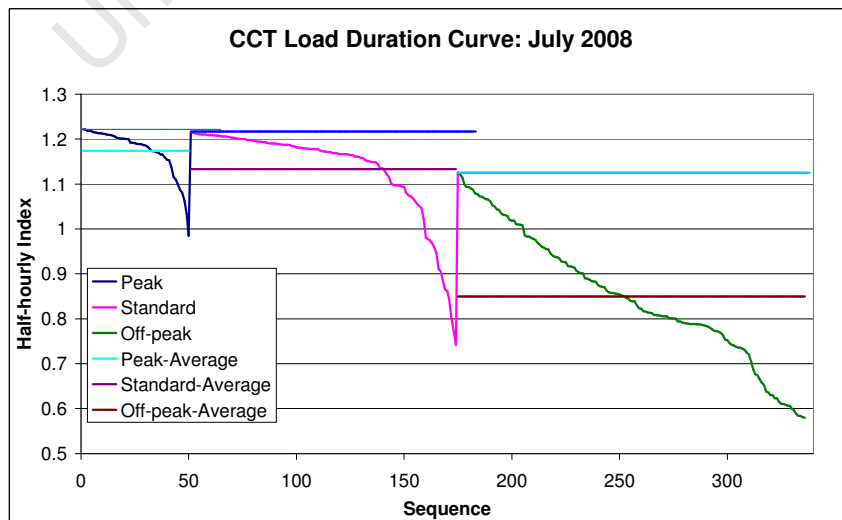


Figure 7-12 CCT Weekly Load Duration Curve: July 2008

The evening peak restriction appears to be implemented widely, even for the other supply points that are on the Megaflex tariff. The minimum values for the Standard and Peak periods coincides with the equivalent regional times of 06h00 and 07h00, respectively, on Mondays. Similarly, the weekly peak also coincides with the regional peak on Tuesdays.

Despite CCT's significant residential load component, they have managed to limit their evening peak in comparison to the region as a whole.

Weekday peak index	1.222
Weekday peak incidence	19h30
07h00 index to weekday peak ratio	88%
Weekday morning peak incidence	09h30
Weekday morning peak to weekday peak ratio	99.6%
Weekday min incidence	03h30
Weekday min to Weekday peak ratio	63%
Sunday peak incidence	19h30
Sunday peak index to weekday peak ratio	92%
LF	82%

	P	S	OP
Max of Half-hourly Index	1.222	1.217	1.125
Average of Half-hourly Index	1.174	1.133	0.850
Min of Half-hourly Index	0.985	0.742	0.580

Table 7-4 City of Cape Town Weekly profile Summary

CCT maintains a higher LF during the weekdays, particularly Monday to Thursday for the Standard and Peak periods – 95% and 97% respectively. In addition, the ratio of averages of Standard to Peak period is 98.2%. It is thus difficult to separate the Standard period from the Peak period (at least visually). Even though the shape of the profile is considerably *flatter* during the Standard and Peak periods of weekdays, there is still a correlation to the regional profile. However, it is clear that CCT employs load management during the Peak periods that implies a strong awareness of the higher cost implications of that period.

7.4 KSACS Customers

The KSACS customer Weekly profile is shown in Figure 7-13 to Figure 7-15. The KSACS group is divided into 3 separate groups as per Chapter 6 to highlight differences in this group.

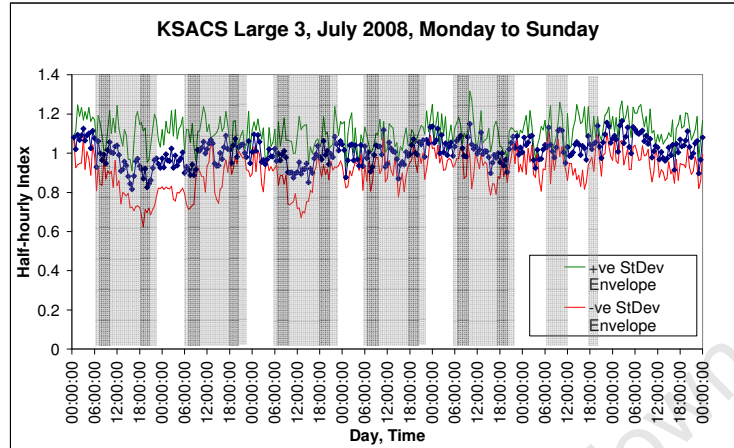


Figure 7-13 KSACS Large 3 Weekly Demand Profile: July 2008

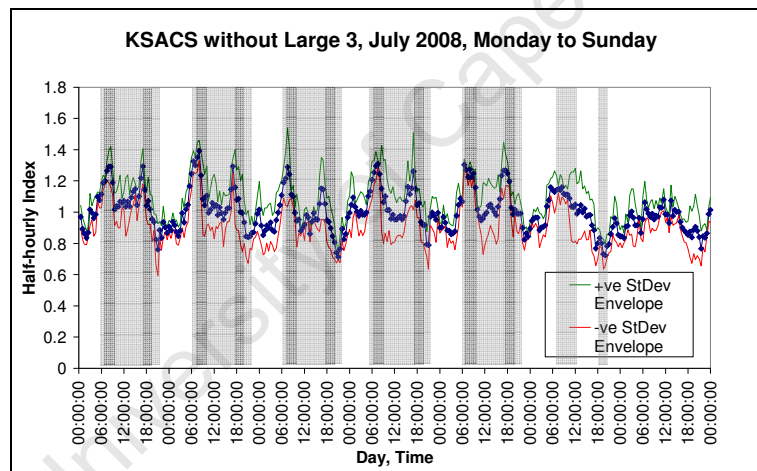


Figure 7-14 KSACS without Large 3 Weekly Demand Profile: July 2008

From a daily demand perspective, it would seem that the 3 largest KSACS customers are avoiding the Peak periods as illustrated by decreased demand for this period.

Load starts increasing again in the Off-peak period from 22h00 onwards. In this particular month, these 3 customers tend to peak on the Sunday at 02h30 (Off-peak) and their peak during the week is at 10h00 (start of the Standard period).

When the LDC is plotted in Figure 7-16 the Off-peak Average is the highest with the Standard Average only marginally higher than the Peak Average; the Off-peak maximum value is the highest with the Peak maximum the lowest of the three periods.

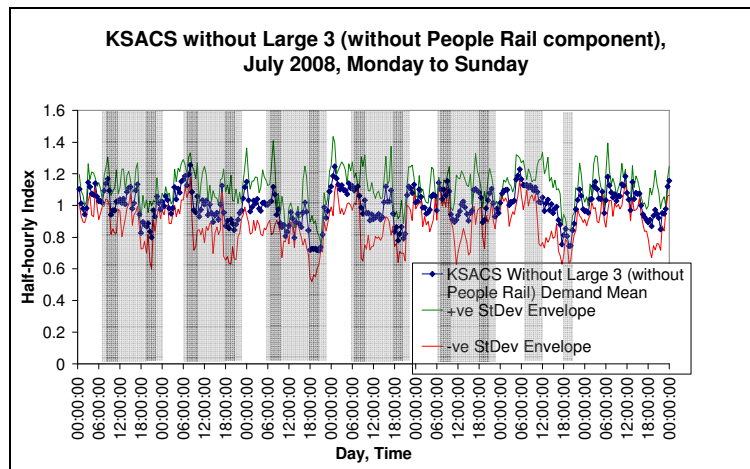


Figure 7-15 KSACS Large 3 (without People Rail component) Weekly Demand Profile: July 2008

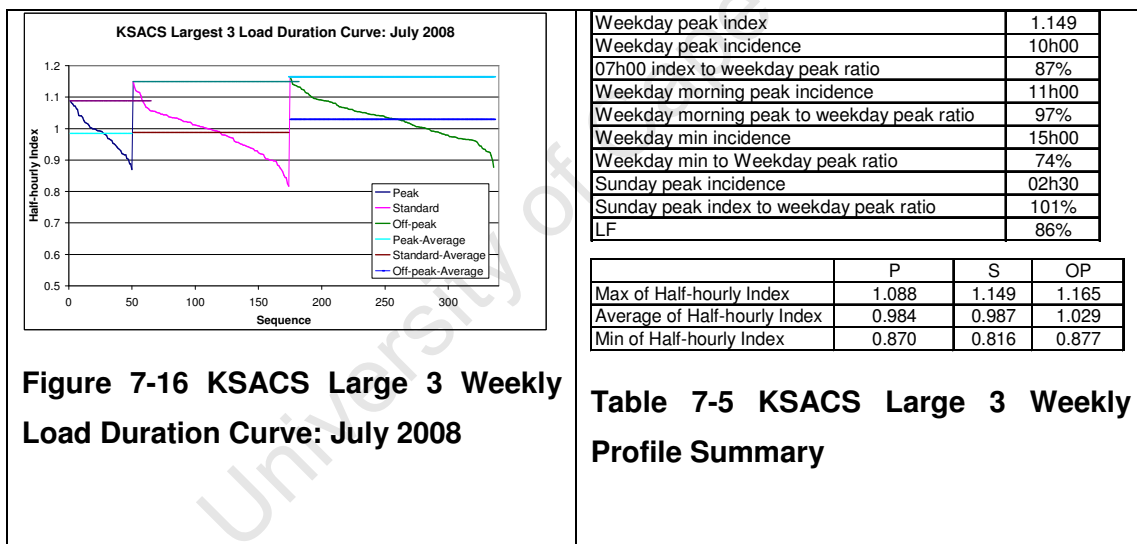


Figure 7-16 KSACS Large 3 Weekly Load Duration Curve: July 2008

Weekday peak index	1.149
Weekday peak incidence	10h00
07h00 index to weekday peak ratio	87%
Weekday morning peak incidence	11h00
Weekday morning peak to weekday peak ratio	97%
Weekday min incidence	15h00
Weekday min to Weekday peak ratio	74%
Sunday peak incidence	02h30
Sunday peak index to weekday peak ratio	101%
LF	86%

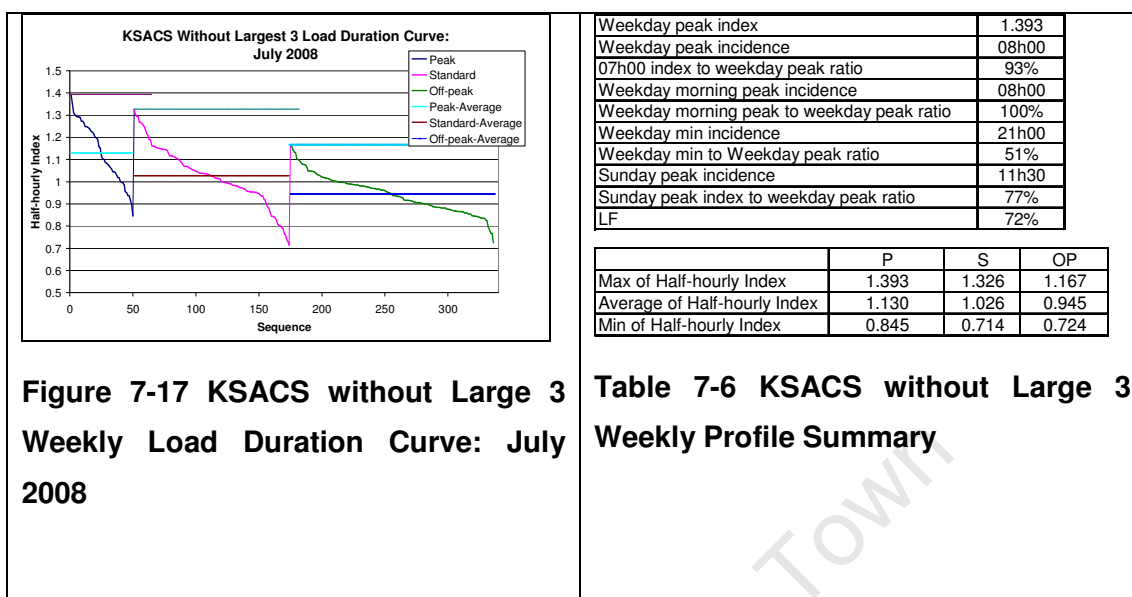
	P	S	OP
Max of Half-hourly Index	1.088	1.149	1.165
Average of Half-hourly Index	0.984	0.987	1.029
Min of Half-hourly Index	0.870	0.816	0.877

Table 7-5 KSACS Large 3 Weekly Profile Summary

KSACS' largest 3 customers seem to have capacity to shift load from of Peak and Standard periods to the cheaper Off-peak periods while appearing to limit their activities during the Peak periods. There does not appear to be a correlation between this group of customers and the regional profiles.

The balance of the sample of KSACS customers as shown in Figure 7-17 (KSACS Customers without Large 3) is dominated by rail customers. Their peak for the week is during the week at 08h00 on a weekday which contributes to the highest average and maximum values being registered for the Peak period. Activities seem to be scaled down during the evening and weekend periods which results in the lowest

average and maximum values for the Off-peak period. The lowest minimum value is registered for the Standard period which coincides with the 21h00 weekly minimum before an increase (relatively) at the start of the Off-peak period.



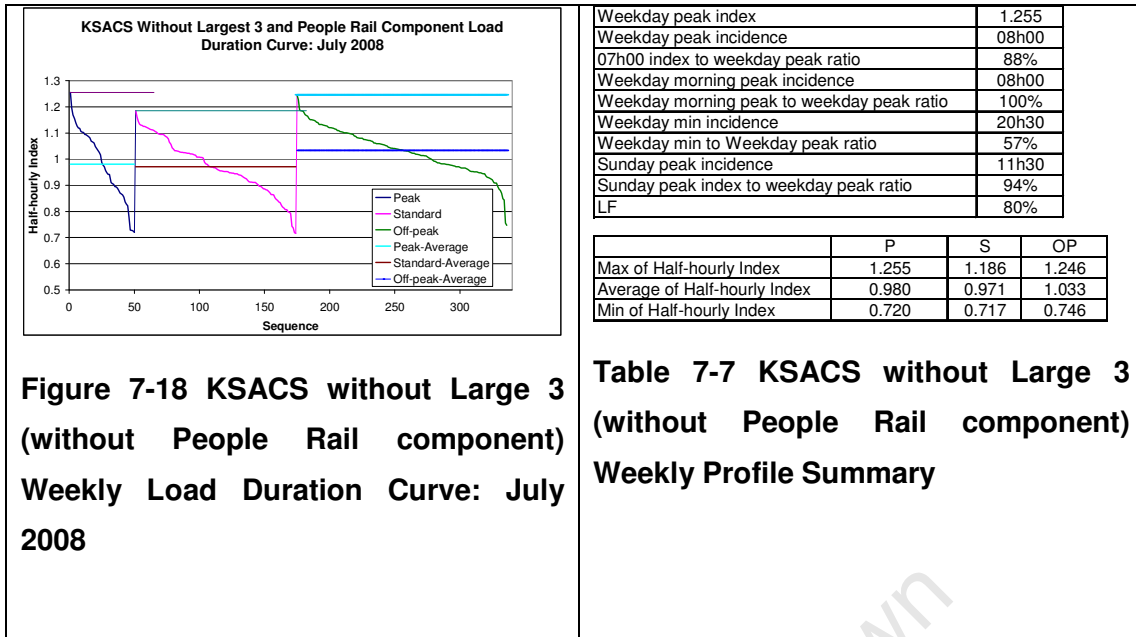
Weekday peak index	1.393
Weekday peak incidence	08h00
07h00 index to weekday peak ratio	93%
Weekday morning peak incidence	08h00
Weekday morning peak to weekday peak ratio	100%
Weekday min incidence	21h00
Weekday min to Weekday peak ratio	51%
Sunday peak incidence	11h30
Sunday peak index to weekday peak ratio	77%
LF	72%

	P	S	OP
Max of Half-hourly Index	1.393	1.326	1.167
Average of Half-hourly Index	1.130	1.026	0.945
Min of Half-hourly Index	0.845	0.714	0.724

Table 7-6 KSACS without Large 3 Weekly Profile Summary

The rail segment that is responsible for freight is particularly dominant (from an energy perspective) while the people segment causes demand peaks during the TOU Peak periods. There is a peak in the morning Peak period as people go to work while there is another peak between 17h00 and 18h00 as people go home in the evening. Hence, there is a correlation to the regional profile in terms of period of the day that the peak is registered; however, the respective peak times appear separated by at least an hour.

If one removes the people rail component, one would expect that the profile for the week would have less demand during the Peak period, specifically the morning Peak period. This assumption is justified as the average value for Peak period decreases by about 15% as shown in Figure 7-18. The Off-peak average is the highest with the Standard average the lowest. The Peak period maximum is only marginally higher than Off-peak maximum with Standard maximum being the lowest. As the average values could be viewed as more indicative of the energy consumption as opposed to the maximum value, the implication is that this group appears to have the capacity to shift energy consumption to the least expensive Off-peak period. Thus there appears to be little correlation to the regional profile.



7.5 Typical Non-Agricultural profile

When the daily profile is considered in Figure 7-19 it appears that Non-Agricultural LPU customers are avoiding the Peak periods by peaking during the Standard periods during the weekdays.

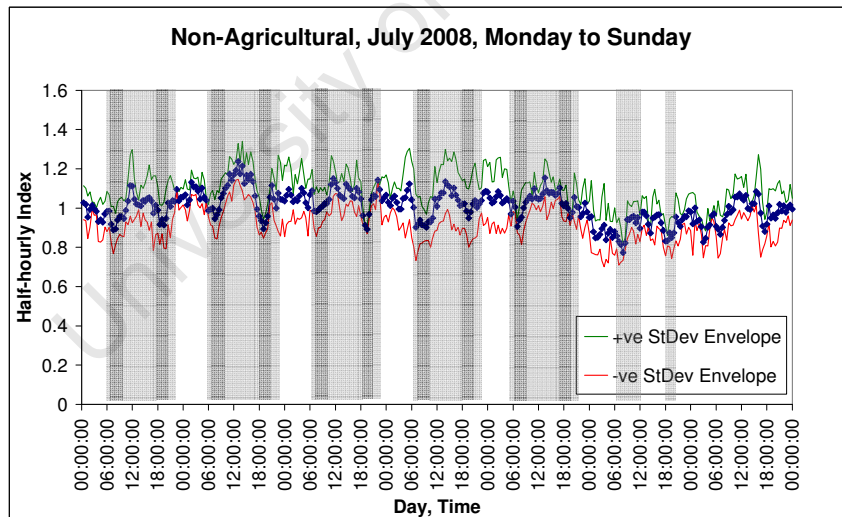
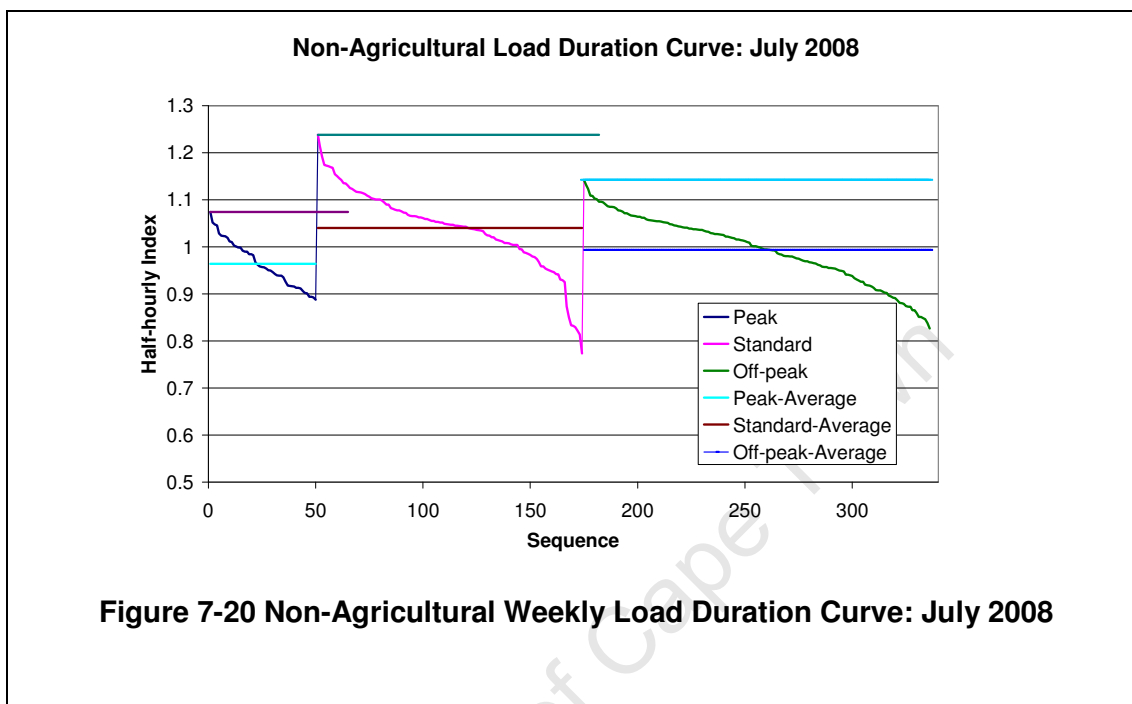


Figure 7-19 Non-Agricultural Weekly Demand Profile: July 2008

Load starts to decrease during the Peak periods and tends to increase afterwards on a consistent basis, firstly into the Standard period, and then further into the Off-peak period. Activities appear to be scaled down on Saturdays before increasing marginally on Sundays for July 2008.

When the LDC is plotted in Figure 7-20, the Standard period indicates the highest maximum and average values for the study period (as summarised in Table 7-8). The Peak period has the lowest maximum and average values over the same period. The Standard period indicates the lowest minimum value which coincides with the scaled down activities of Saturdays.



Weekday peak index	1.238
Weekday peak incidence	13h00
07h00 index to weekday peak ratio	73%
Weekday morning peak incidence	11h00
Weekday morning peak to weekday peak ratio	95%
Weekday min incidence	19h30
Weekday min to Weekday peak ratio	72%
Sunday peak incidence	15h30
Sunday peak index to weekday peak ratio	88%
LF	81%

	P	S	OP
Max of Half-hourly Index	1.075	1.238	1.142
Average of Half-hourly Index	0.964	1.040	0.993
Min of Half-hourly Index	0.888	0.774	0.827

Table 7-8 Non-Agricultural Weekly profile Summary

As average values are highest for the Standard and Off-peak periods, it appears that this group has the capacity to shift energy consumption from the expensive Peak period to the less expensive Standard and Off-peak periods. There appears to be little correlation between Non-agricultural customers and the regional profile.

7.6 Non Municipal rural supplies

From a daily demand perspective, Agricultural customers peak during the day during Standard period as shown in Figure 7-21. Load tends to decrease during the evening Peak period and increases soon afterwards before continuing on a decreasing trend into the Off-peak period. There is a consistent decrease at about 12h30 to 13h00 every weekday which could be indicative of a lunch time break where processes associated with food processing might be scaled down. Activities over the weekend tend to be scaled down considerably relative to the weekday.

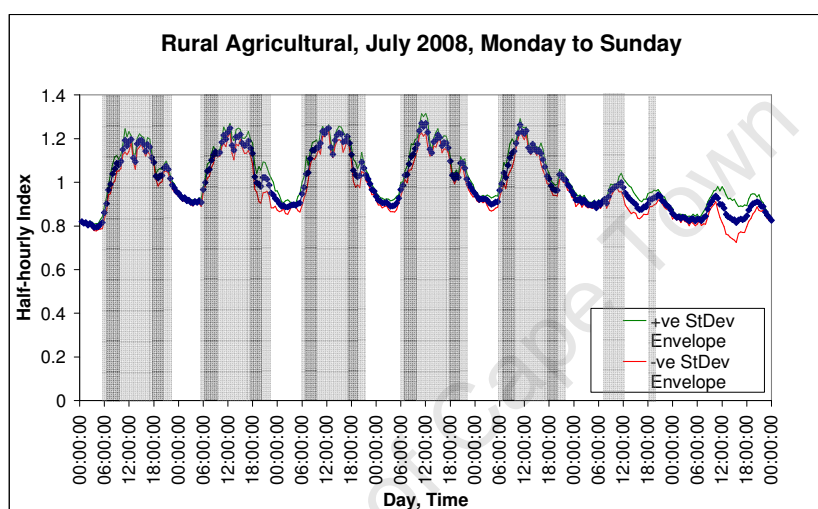


Figure 7-21 Rural Agricultural Weekly Demand Profile: July 2008

In the morning, there is an increase during the morning Peak period as the workday starts, and at the end of the workday the demand decreases at about 17h00 with a *slight* increase at the start of the evening Standard period. However, demand continues to decrease into the Off-peak period with no subsequent increase until the start of the next workday. Even though it appears that these customers are avoiding the Peak periods, it might be more a matter of a typical workday cycle. Untested by this thesis, the typical workday cycle might also be influenced by stronger social habits of rural communities and a possible preference or even insistence on more family and community time after the typical workday.

When the LDC is plotted in Figure 7-22, the Standard period indicates the highest maximum and average values (quantified in Table 7-9) which coincide with the typical weekday workday. The Off-peak period has the lowest values which coincide with the scaled down activities over the weekend.

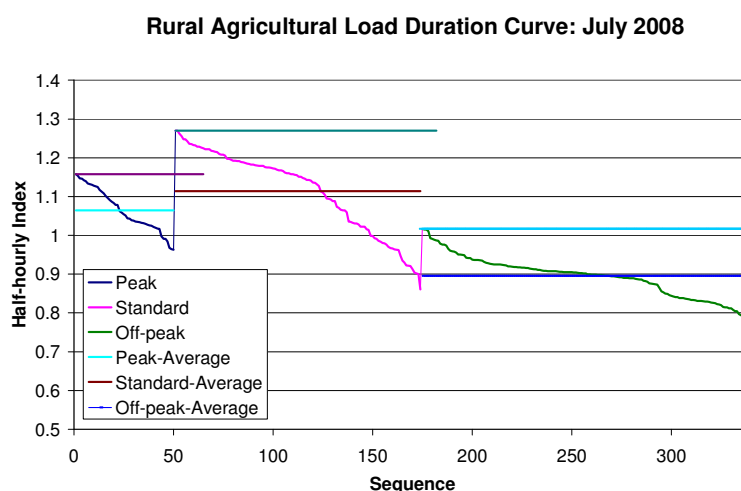


Figure 7-22 Rural Agricultural Weekly Load Duration Curve: July 2008

The profile of this group of customers appears to represent a successful attempt to reduce load during Peak periods by shifting load to the Standard period. Even though there is a similarity in terms of the order of the average values for the different periods there appears to be little correlation between this group and the regional profile.

Weekday peak index	1.270
Weekday peak incidence	11h00
Weekday morning peak incidence	11h00
Weekday morning peak to weekday peak ratio	100%
07h00 index to weekday peak ratio	81%
Weekday min incidence	02h00
Weekday min to Weekday peak ratio	70%
Sunday peak incidence	10h30
Sunday peak index to weekday peak ratio	74%
LF	79%

	P	S	OP
Max of Half-hourly Index	1.158	1.270	1.017
Average of Half-hourly Index	1.064	1.114	0.896
Min of Half-hourly Index	0.963	0.860	0.794

Table 7-9 Rural Weekly profile Summary

7.7 Rural Municipal Supplies

From a daily demand perspective the Rural Municipalities repeatedly peak in the Peak periods of the weekday as shown in Figure 7-23. As mentioned earlier, this can be attributed to the residential component that has a significant influence on overall demand curves.

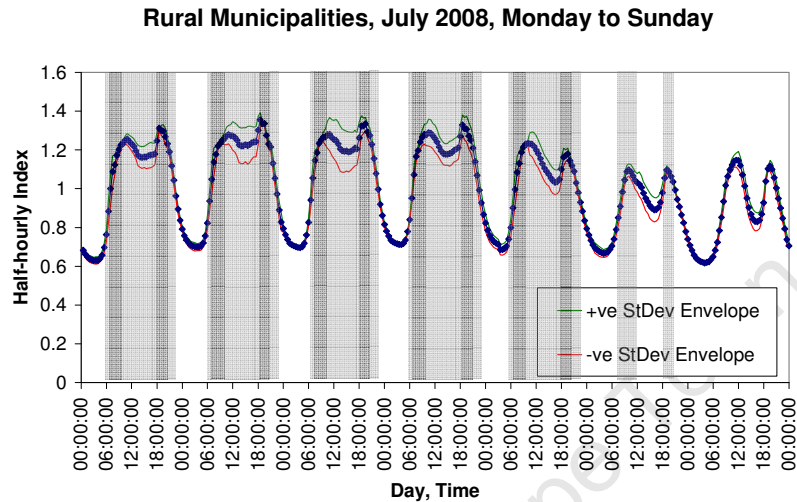


Figure 7-23 Rural Municipalities Weekly Demand Profile: July 2008

When the LDC is plotted in Figure 7-24, the Peak period indicates the highest maximum and average values while the Off-peak period has the lowest (quantified in Table 7-10). This group of customers do not appear to be able to move their load from the Peak period to the less expensive periods in any noticeable way.

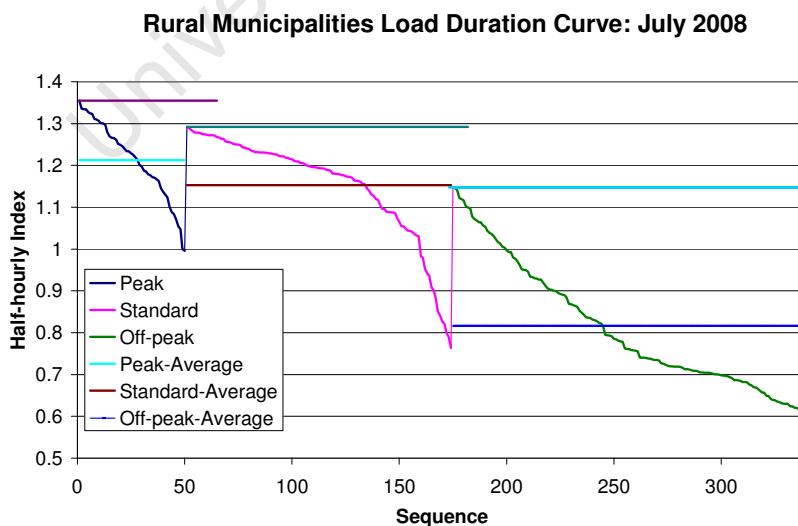


Figure 7-24 Rural Municipalities Weekly Load Duration Curve: July 2008

Weekday peak index	1.355
Weekday peak incidence	18h30
07h00 index to weekday peak ratio	79%
Weekday morning peak incidence	10h30
Weekday morning peak to weekday peak ratio	95%
Weekday min incidence	03h30
Weekday min to Weekday peak ratio	51%
Sunday peak incidence	11h30
Sunday peak index to weekday peak ratio	85%
LF	74%

	P	S	OP
Max of Half-hourly Index	1.355	1.292	1.147
Average of Half-hourly Index	1.212	1.153	0.816
Min of Half-hourly Index	0.996	0.763	0.618

Table 7-10 Rural Municipalities Weekly profile Summary

Sundays represent a peak at about 11h30 as opposed to the region's equivalent peak at 20h00. Rural municipalities in the Western Region represent a demographical structure where, generally, coloured people are considered the majority in the area. Thus a similar scenario to Low Income housing in Belhar appears to be evident.

Notwithstanding the Sunday profile, there seems to be a direct correlation between Rural Municipalities' demand profile and the regional demand profile.

7.8 Chapter Summary

CCT peaks in the morning and evening Peak periods but the evening peak is practically equivalent to their morning peak. The Peak period average value is only marginally higher than the Standard Average values which is indicative of a high LF for the sum of these periods. It is evident that load management is in place which is a strong indication of the awareness of tariff implications.

Profiles from Eskom's Electrification areas suggest that the LF for demand is the lowest of Eskom's residential groups. Eskom Residential customers and Rural Municipalities peak inside the morning and evening Peak periods. There is a direct correlation between these customers and the regional profile. With the exception of CCT, it was evident there is a strong correlation between LPU's with significant residential components and the regional profile. These LPU's (Rural Municipalities) appear unable to shift load from the Peak period at significant levels.

KSACS customers on the whole, Agricultural and Non-agricultural appear to have the capacity to shift load from the expensive Peak period by registering higher Average and maximum values in the Standard or Off-peak periods. However, Agricultural customers' profile appears more to be dictated by the *average workday* cycle rather than tariffs. There is very little correlation between these customers and the regional profile.

One of the major issues that needed to be investigated was whether LPUs were responding to the inherent pricing signal of TOU tariffs. As mentioned before, in order to determine this with more certainty one would have needed a profile of these customers' behaviour prior to TOU tariffs as a reference. However, as this is not possible, what conclusions can be drawn from these findings? There is a correlation between the higher costs of energy (during the Peak period) and reduced consumption while an increase in energy consumption is noted when energy is cheaper (during the Standard and Off-peak periods) for LPUs without a significant residential component.

8. Discussion of Western Region Analysis Findings

It has been shown that the Western Region peaks during the High Demand season from an energy and demand perspective over the study period of 2004-2008. A strong correlation was found to Eskom's typical residential profiles. LPU's with significant residential sectors displayed a similar characteristic of High Demand season peaks.

When the weekly profiles for the month of July 2008 were considered in Chapter 7, Eskom's different residential profiles displayed a tendency to peak during the different Peak periods of the day. A strong correlation was once again displayed between Eskom's typical residential profiles and the LPU's with significant residential sectors. This ultimately contributed to a regional profile that displayed a strong residential influence. CCT appears to be the exception despite their significant residential component.

The different customer groupings have different load factors that ultimately contribute to the region's load factor. Considering the generation mix in South Africa, it is important to have a better understanding of the relationship between load factor and tariffs.

This chapter will discuss the following:

1. The dynamics and history of the residential customer groupings in South Africa with specific focus on the poorer groups.
2. The different customer groupings' annual and weekly profiles in relation to the TOU tariffs.
3. The Western Region's biggest customer, the City of Cape Town
4. The South African requirement of tariffs.
5. What are the options?
6. Nersa's role regarding tariffs
7. The ideal customer tariff relationship.

8.1 The Dynamics and History of the South African Residential sector

The residential sector has been categorised in this thesis into three different segments, viz. Middle Income, Low Income and Electrification. Each segment has its own social

dynamics that could have an impact on consumption habits, including electrical energy. This is no different to other parts of the world; however, the political history of these segments in South Africa has a significant impact on how these segments may be charged for their different electrical energy consumption habits.

South Africa comes from a deeply divided racial past where all inclusive democracy was only achieved in 1994. The Apartheid system was used by a minority government to cause racial segregation with the white minority enjoying a relative First World existence with associated services while the majority of the population - black people – was subjected to minimal government support and very basic, and often, no services at all. These actions, amongst others, have resulted in a society that was not only racially divided but also economically very different.

In 1994 a government was elected by all of the people, and hence representative of all of the people with Nelson Mandela being elected as the country's first black president. Part of the mandate of the new government of the day was the social responsibility to alleviate the poverty that was endemic to the majority of its electorate. *Access to electricity is generally seen as an important step in socio-economic development* [Prasad et al, 2006].

Gaunt (2003) states that the *responsibility for electrification or poverty alleviation or both, therefore appears to be based on:*

- *reducing socially inspired terrorism and aggression,*
- *increasing political influence,*
- *humanitarian reasons,*
- *religious beliefs, and*
- *generalised feelings that it is "right" to support the weak in their weakness and hope for a better future.*

The Electrification and, to a lesser extent, the Low Income segments are thus important for reasons that are not necessarily commercial. Providing electricity to the poor does not appear to have to be commercially viable as the *other* reasons as stated above may prove to be more appropriate.

Providing electricity to the poor has been accepted as a social responsibility of the government. President Mbeki, in his State of the Nation address in 2004 said that “...within the next eight years, ensure that each household has access to electricity” [Mbeki, 2004] and this would be implemented by Eskom and Local Government.

Further, notwithstanding that the average increase granted to Eskom by Nersa amounted to 31.3% for the year ending March 2010, Nersa also ruled that the price increase *be limited to 15%* to Eskom’s and the municipalities’ poor residential customers [Eskom, 2009e].

In terms of tariffs, this implies that cross subsidisation would be part of any tariff package and that the poor need to be protected from the complete financial burden of electricity tariffs. Table 8-1 indicates the typical levels of subsidies that were submitted as part of Eskom’s tariff application to Nersa in 2009 as part of its *Proposed Revenue Application Multi-Year Price Determination 2010/11 to 2012/13 (MYPD2)* [Eskom, 2009e].

Based on these untested Eskom calculations and subsidies, it is evident that the Homelight tariff would typically be subsidised by 55% and would be available to Eskom’s residential customers inclusive of *low-usage single phase residential supplies in urban and electrification areas* [Eskom, 2009d]. It is evident that subsidies are not limited to poor residential customers but across the urban residential spectrum as well as tariffs available to rural customers.

Tariff	Average Cost	Average revenue	Subsidy	% subsidy
Megaflex	R 40,883	R 44,177	R 3,294	7%
Miniflex	R 832	R 895	R 64	7%
Nightsave Urban	R 4,481	R 4,867	R 385	8%
Nightsave Rural	R 2,325	R 1,888	-R 438	-23%
Ruraflex	R 1,817	R 1,139	-R 678	-59%
Businessrate	R 452	R 535	R 83	16%
Homepower	R 1,533	R 1,424	-R 109	-8%
Homelight	R 6,090	R 3,926	-R 2,164	-55%
Landrate	R 4,242	R 3,242	-R 1,000	-31%

Table 8-1 Estimates Subsidies for the different Tariffs [Eskom, 2009e]

Customers on the Megaflex, Miniflex, Nightsave Urban and Businessrate tariffs are effectively subsidising customers on the other tariffs available to Eskom customers. Government further compensates the local municipalities (and through them, Eskom) for the Free Basic Electricity allocation of 50kWh to poor residential customers.

As noted in section 7.2, Eskom’s residential customers’ weekly profiles for July 2008 appear to have a strong correlation to the regional profile from a Weekday peak incidence (time of day) perspective while there seems to be a much wider window for the Weekday morning peak incidence. It is thus not clear how strong the correlation is between the residential segment morning peak incidence and the regional Weekday morning peak incidence.

Singh [2008] (based on a study by A Gildenhuys and Statistics South Africa, General Household Survey 2006) indicated that Electrification households tend to use electricity mostly for lighting, cooking and boiling water in a kettle as shown in Figure 8-1. During winter space heating tends to contribute significantly to the total electrical energy consumption of these households. Poorer people have less material wealth and the expectation would be that there would be less electrical appliances in their homes.

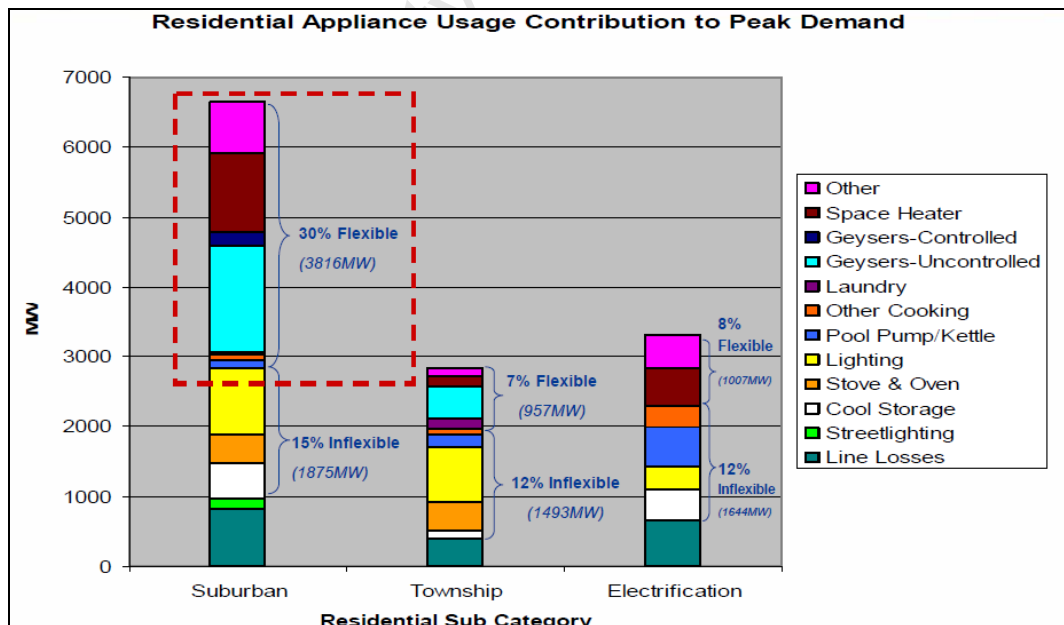


Figure 8-1 Residential Appliance Usage Contribution to Peak Demand (National System) [Singh, 2008]

Singh further refers to *Suburban* households which one can assume are similar to Middle Income households. These households tend to use electrical energy mostly for hot water cylinders (*Geysers*), space heating (in winter), lighting and cooking. She refers to *Other* which one can assume refers to the additional appliances that are more likely to be found in middle income households and seems to make a significant contribution to the overall contribution.

Due to lower ambient temperatures in the colder winter months, space heating and hot water cylinder energy consumption would be higher during the High Demand Season compared to the relatively warmer months of the Low Demand Season. As these loads contribute significantly to the Peak Demand it implies that the colder winter months would result in higher residential load and hence greater contribution to the Peak Demand. Areas with a significant residential segment would therefore tend to display an annual peak during the colder winter months of the High Demand Season.

When Table 8-2 is considered the seasonal differences between the Middle Income and poorer households come to the fore even more. The Middle Income segment has the highest Ratio of High Demand vs Low Demand Season averages by a considerable margin, the gap between the minimum and maximum is the greatest, the High Demand Season Average is the highest. As the Middle Income group falls within the higher LSM groups, they would also have a comparatively higher ADMD as a group. The greater seasonal variation in combination with the higher ADMD implies that on an annual basis, there is a bigger contribution per Middle Income residential customer relative to the other residential groups to the regional High Demand Season peak.

	Electrification		Low Income		Middle Income	
	Demand	Energy	Demand	Energy	Demand	Energy
Average Low Demand Season Monthly Index	0.971	0.972	0.961	0.956	0.925	0.927
Average High Demand Season Monthly Index	1.082	1.072	1.113	1.126	1.211	1.224
Ratio of HD Average to LD Average	1.114	1.103	1.159	1.178	1.310	1.321
Max Monthly Index	1.092	1.105	1.138	1.147	1.260	1.258
Peak Month	July	July	July	July	Aug	July
Min Monthly Index	0.866	0.885	0.862	0.831	0.749	0.747
Min Month	Dec	Feb	Jan	Feb	Jan	Feb

Table 8-2 Residential Customer Annual Profile Summary

The Homelight tariffs include a flat energy rate for the whole day and whole year. The tariffs available for CCT and Rural Municipalities' residential customers generally offer the same type of flat tariff at different costs. There is no pricing signal for residential customers in the region to change their consumption habits. However, for poorer residential customers who benefit from FBE, there is effectively an Inclining block tariff with 2 blocks (first 50kWh is free). As for Middle Income households, tariff increases have not been limited and this could result in reduced consumption due to the increased expense. In addition, an Inclining Block tariff has been approved by Nersa from April 2010 onwards [Eskom, 2010].

No data is available for CCT and the Rural Municipalities' individual customer groupings' profiles. As the social patterns of a community largely determine the electricity consumption profiles, it should be noted that these individual residential customer groups (CCT and Rural Municipalities) are effectively neighbouring communities to Eskom's residential groups. It is therefore assumed that residential customers within municipal borders with similar income levels (TO Eskom's residential customers) would have similar social habits as Eskom's residential customers within the region and would ultimately have very similar load profiles.

8.2 Annual Demand Profiles

Summaries of some the results of Chapter 6 are shown in Table 8-3 and Table 8-4.

Demand	Western Region	CCT	KSACS Large 3	KSACS without Large 3	Non-Agricultural	Agricultural	Rural Municipalities
Average LDS Monthly Index	1.043	0.974	0.996	0.993	1.001	1.038	0.990
Average HDS Monthly Index	0.985	1.065	1.016	1.005	1.002	0.877	1.033
HDS Average:LDS Average	1.059	1.094	1.021	1.012	1.001	0.846	1.043
Max Monthly Index	1.053	1.074	1.041	1.036	1.029	1.318	1.036
Peak Month	July	Aug	Aug	Nov	March	March	Aug
Min Monthly Index	0.958	0.944	0.954	0.963	0.969	0.795	0.947
Min Month	Dec	Dec	Sep	Jan	Jan	Oct	Oct

Table 8-3 Annual Demand Profile Summary

Energy	Western Region	CCT	KSACS Large 3	KSACS without Large 3	Non-Agricultural	Agricultural	Rural Municipalities
Average LDS Monthly Index	0.978	0.963	0.987	0.985	0.985	1.012	0.974
Average HDS Monthly Index	1.007	1.052	0.971	0.976	1.001	0.912	1.019
HDS Average:LDS Average	1.030	1.093	0.984	0.991	1.016	0.901	1.046
Max Monthly Index	1.015	1.066	1.048	1.054	1.044	1.402	1.034
Peak Month	Aug	Aug	May	Sep	Sep	Feb	Feb
Min Monthly Index	0.960	0.907	0.909	0.913	0.867	0.689	0.938
Min Month	Dec	Jan	Feb	Jan	Jan	Oct	Oct

Table 8-4 Annual Energy Profile Summary

From Table 8-3 and Table 8-4 it is evident that while the Western Region tends to peak in July from a demand perspective, none of the LPU groups peaks in the same month. However, the poorer households indicate a July peak for demand.

It was noticed that there is a correlation between LPUs with a significant residential component and a High Demand Season annual peak. It was clear that CCT and Rural Municipalities – with their significant residential components - peak during the High Demand Season.

KSACS Large 3 customers also peak during the High Demand Season from a demand perspective but not from an Energy perspective where a May month peak was registered. The Low Demand Season Average Index for energy is higher than the equivalent High Demand Season value. Over the study period there does seem to be a marginal preference for the Low Demand Season.

KSACS without Large 3 customers tends to peak in Nov from a demand perspective while registering a September peak for energy. Even though the High Demand Season Average for demand is the higher value, there is practically no difference between the equivalent energy values. This implies lack of preference for any particular season from an energy perspective.

Non-agricultural customers register a peak demand in March while indicating a September month peak for energy. While both values are registered during the Low Demand Season there is practically no difference between the seasonal average values for demand. This implies lack of preference for any particular season from a demand

perspective. The High Demand Season Average Energy Index is higher than the equivalent Low Demand Season value which could imply a preference for former season. However, when considering the Energy Profile it shows that the energy values for December through to February were considerably lower than the rest of the Low Demand Season and would therefore present a lower value. In addition, January and February would include the values in 2008 when the highest frequency of load shedding occurred.

Agricultural customers' peaks in February to April and this is due to the seasonality of their crops rather than a response to higher prices in the High Demand Season. The seasonality of tariffs might not be effective on Agricultural customers.

Therefore, from an annual profile perspective for both demand and energy, CCT, Rural Municipalities (February value is only marginally higher than August value) and Eskom's residential customers correlates to the regional profile. As these LPUs have a significant residential segment, the implication is that the residential segment across the region contributes significantly to the regional profile's peak during the High Demand Season.

It was not possible to access data prior to the advent of TOU tariffs within Eskom supply areas. Even though LPUs without residential segments appear to be avoiding the High Demand Season, one cannot say conclusively that this is solely due to the impact of tariffs as the possibility exists – even if only remotely – that this consumption pattern was followed regardless prior to the advent of TOU tariffs. The strongest statement that can be made based on the findings over the study period is:

1. LPUs with a significant residential component showed little demand response to the high costs of the High Demand Season.
2. LPUs without significant residential components tend to avoid the High Demand Season that is normally associated with higher costs.
3. LPUs with significant residential segments do not appear to have that flexibility as residential customers appear to follow the social habits that are common to the area and have no incentive to change their habits which results in evening peaks during the evening Peak periods.
4. The response of LPUs to the seasonal aspect of TOU tariffs is determined by the capability to control their demand.

8.3 Daily Demand profiles

It has been shown that there is a strong correlation between residential customers' Weekday peak incidence and the equivalent regional value during the evening Peak period. There appears to be more diversity during the morning period where Electrification customers do not even peak during the morning Peak period. A summary of the LPU groups' weekly profile for the study period is shown in Table 8-5.

	Western Region	CCT	KSACS Large 3	KSACS without Large 3	Non-Agricultural	Agricultural	Rural Municipalities
Weekday peak index	1.245	1.222	1.149	1.393	1.238	1.270	1.355
Weekday peak incidence	19h00	19h30	10h00	08h00	13h00	11h00	18h30
07h00 index to weekday peak ratio	83%	88%	87%	93%	73%	81%	79%
Weekday morning peak incidence	11h00	09h30	11h00	08h00	11h00	11h00	10h30
Weekday morning peak to weekday peak ratio	95%	100%	97%	100%	95%	100%	95%
Weekday min incidence	04h00	03h30	15h00	21h00	19h30	02h00	03h30
Weekday min to Weekday peak ratio	62%	63%	74%	51%	72%	70%	51%
Sunday peak incidence	20h00	19h30	02h30	11h30	15h30	10h30	11h30
Sunday peak index to weekday peak ratio	91%	92%	101%	77%	88%	74%	85%
LF	81%	82%	86%	72%	81%	79%	74%

Table 8-5 Summary of Weekly profile: July 2008

Of all the LPU groups only CCT and Rural Municipalities' Weekday peak incidence occurs during the evening Peak period. Their significant residential component would most likely have contributed to the incidence of the peak value. CCT's relatively flat weekday profile (with equivalent morning and evening peak values) is significantly influenced by the Nightsave tariff (for its largest supply point) and its load management programs including pump storage and geyser control.

It is noted that KSACS Large 3 customers have their peak incidence on a Sunday at 02h30 while Non-agricultural customers peak during the Weekday Standard period. Non-agricultural customers appear to be responding to the tariffs as load is decreased during the expensive Peak periods and consistently increases thereafter. These actions are indications of these LPUs' capacity to shift load from the expensive Peak periods to the less expensive periods.

Agricultural LPUs peak during the Standard period. These LPUs reduce load during the evening Peak period; however load does not increase after the Peak period. Their

actions may be influenced more by the typical workday cycle and, perhaps, the stronger social-orientated habits of rural communities that are more likely to work a *normal workday* and having more family or community time afterwards.

Of the LPU groups only CCT and KSACS without Large 3 customers' Weekday morning peak incidence occurs during the morning Peak period. All other LPU groups' Weekday morning peak incidence is around 10h30 to 11h00 which correlates closely to the regional equivalent incidence which is also outside the morning Peak period at 11h00.

The regional LF for the study period is 81% which is less than 3 LPU groups, including CCT, KSACS Large 3 and Non-agricultural customers. The residential customers have LFs less than 70% with the Electrification residential group having the lowest LF.

The average hourly (for the Western Region) and half-hourly values (for the different LPUs) for the study period over the different periods are shown in Table 8-6. CCT and Rural Municipalities register the highest average values during the Peak period which can be attributed to their residential segments.

KSACS without Large 3 customers follow the same trend; however, when the People Freight customers are removed from this group, the Off-peak period registers the highest average values. It should be noted that, as a result of rail congestion, there is a possibility that KSACS without Large 3 and People Freight customers might be forced into the non-Peak periods due to the need for the People Freight customers to operate during the Peak periods. This combination leads to a higher LF for this group. This implies that the LF for this LPU would be expected to be higher should the People Freight customers be removed as the People Freight customers tend to maximise its operation during Peak periods. This also implies that the People Freight customers might not have the capacity to shift its load out of the Peak period as the demand for its services peaks during the Peak period. These customers mitigate this fact by charging lesser rates for qualifying customers outside their own peak periods [Cape Metrorail, 2010].

The other LPU groups have their highest average values outside the Standard or Off-peak periods which is an indication of their capacity to shift load from the Peak periods.

	Average Values		
	P	S	OP
Western Region	1.137	1.112	0.877
CCT	1.174	1.133	0.850
KSACS Large 3	0.984	0.987	1.029
KSACS without Large 3	1.130	1.026	0.945
KSACS without Large3 without People Freight	0.980	0.971	1.033
Non-Agricultural	0.964	1.040	0.993
Agricultural	1.064	1.114	0.896
Rural Municipalities	1.212	1.153	0.816

Table 8-6 Summary of Load Duration Curve tables for Period Averages Indices

Once again, on a regional level, it was not possible to access enough historical customer data to ascertain whether the consumption habits of the different customer groups have changed from years prior to the advent of TOU tariffs. However, the following is more certain:

1. LPUs with a significant residential component (or dependency on demand from people like People Freight customers) showed little demand response to the high costs of the Peak period.
2. LPUs without a significant residential load component use more energy outside the expensive Peak periods. The fact that some decrease consumption during Peak periods, only to increase the load after the Peak periods, implies a strong awareness of the financial implication of the most expensive period of the day.
3. It appears that the strongest correlation to the regional profile from a peak incidence perspective remains with residential customers and LPUs who have a significant residential component. CCT remains the exception with similar morning and evening peak values and will be discussed separately.
4. The response of LPUs to the daily aspect of TOU tariffs is determined by the capability to control their demand.

As most LPU groups' highest average energy consumption is outside the Peak period, and assuming that it is influenced to a large extent by the higher costs of the period, it is evident that the capacity issues during Peak periods that South Africa is experiencing could have been considerably worse if TOU tariffs were not part of the South African electricity tariffs. However, this statement needs to be balanced with the fact that when load shedding is required during Standard and Off-peak periods, response to TOU tariffs

may actually introduce more load (due to cheaper costs) as opposed to the need for regional/national power rationing.

8.4 CCT

Indications are that CCT are managing their residential sector effectively as they already have a fairly flat daily profile. It also implies that:

- They have implemented effective load management (domestically on hot water cylinders) and self-generation (pump storage and gas) to limit their demand and purchases from Eskom.
- Their non-residential sector appears to fill the valley between the morning and evening peaks.

CCT introduced a TOU tariff in their 2008-9 financial year where the energy costs are 56% more for every period and the demand charge is 232% more than the equivalent values for the Megaflex tariff approved at the same time. The pricing periods coincide with Eskom's TOU periods.

CCT's tariffs prior to the introduction of TOU tariffs in 2008-9 for Large Power Users are similar to Eskom's Nightsave tariff. However, no allowance was made for the different seasons. If an equivalent annual value is determined for the Nightsave tariff and compared to CCT Large Power User tariffs, CCT's demand charge is at least 329% higher. CCT's energy charge is at least 88% higher.

On average, the CCT residential energy rates are 5% cheaper than Eskom. Eskom was granted an average increase of 27.4% in July 2009. All of Eskom's Homelight customers were only subjected to an increase of 11%. However, CCT's residential customers experienced a 9% increase for users of less than 400kWh per month, and about 36% for all other residential customers. Therefore, while Eskom shielded all its residential customers from the increased tariff, CCT only made allowance for the very poor residential customer. It is thus implied that low consumption customers are poor, which might not be the case.

All comparisons between Eskom and CCT does not include a 3% Transmission Percentage Surcharge [Eskom, 2008c] that is added to compensate for the distance from the bulk of the country's generation centres in the northern parts of the country.

CCT supplies the 2nd largest city in South Africa and is appearing to be very effective in terms of load management. They are large enough to have a diverse mix of all types of customers. Until 1 July 2008, they have not had TOU tariffs. They do not appear to have any seasonality built into their Large Power User tariffs. They supply the bulk of Western Region's residential customers including Low income households. The Western Region does have the most inclement winter weather in the country which causes additional space and water heating, mostly in the residential segment, which contributes largely to CCT's High Demand Season peak.

There appears to be large uncertainties about the basis and details of implementing TOU tariffs for CCT customers which is beyond the scope of the analysis of this thesis. It appears that issues could include:

- Is the classical TOU system even required if a Nightsave type tariff already contributes to a flat daily profile?
- Is raising the price the simplistic solution that delivers a more favourable response from large power users?
- What is the CCT hoping to achieve with TOU tariffs?
- What influence does this equivalent Nightsave tariff have over the overall profile in comparison to the various load management measures that are already in place?
- How much more load management capacity is available, if even required considering their already flat profile?

These are issues that cannot be addressed by this thesis and should rather be addressed in a separate study of the impact of CCT's electrical tariffs where access to CCT metering and LPU consumption data would be more readily available.

8.5 What is the South African need in terms of tariffs?

When classical TOU tariffs were launched in 1991 part of the objective for these tariffs was that system LF would be increased by reducing Peak period demand. This was at a time of relative supply surplus.

During 2007 and 2008 in South Africa, load shedding occurred not only during Peak periods but also across all TOU periods. Nersa's findings after a task team was appointed to investigate the cause of the load shedding incidents included:

- *High unplanned maintenance and load losses combined with the usual high planned maintenance of generating units during the period resulted in reduced generating capacity being available from 1 November 2007 to 31 January 2008. Poor coal quality, wet coal, and low stockpile levels contributed to the unplanned generation plant outages and load losses in the period.*
- *Inadequate primary energy procurement and power station production planning impacted coal stockpile levels in the period. Coal stockpiles were allowed to decline to unacceptably low levels and there was a reluctance to obtain supplementary coal due to its high cost and its impact on Eskom's financial position.*
- *In previous load forecasts, Eskom had anticipated the current growth rate. However, the implementation of measures to provide for the growth has been inadequate and slow. In particular, there have been delays in returning the mothballed generation plant to service and the implementation of energy efficiency and demand management initiatives remain behind targets. Eskom's new build programme is experiencing delays of at least a year.*

[EE Publishers, 2008]⁷

Eskom further mentions:

The power system had been vulnerable due to an inadequate reserve margin. This was worsened by low coal levels at our power stations. The immediate coal-related problems were poor quality, lower than expected volumes produced by the mines and logistical issues. The unusually heavy rainfall in January and February 2008 made the handling of coal a near impossibility at some of the stations. [Eskom, 2009c]

⁷ Report refers to *full report being available on Nersa's website*; however, the report was not available in June 2010.

The findings with regard to primary energy, specifically coal management, appear to have been addressed: *Coal stockpile days for the system were taken from an average of 12 days in January 2008 to 20 system days by winter 2008. The average coal stockpile levels now stand at around 41 days, with every power station having stockpile levels above 20 days. There are still issues with the quality of coal, but collaboration with the collieries has improved dramatically.* [Eskom, 2009c]

With respect to the reserve margin:

The reserve margin has moved from around 5% in January 2008 to about 14% in January 2009 (including imports). The reason for this is twofold: technical recovery of the Eskom power system and a drop in demand. [Eskom, 2009c]

The drop in demand was a result of Eskom's *Power Conservation Program* started in July 2008 to encourage Eskom's largest 250 customers to reduce consumption, and the global recession resulting in reduced system demand. However, the Power Conservation Program did not deliver as much as was hoped: *Last year we only achieved a 2% drop in demand as opposed to the call for a 10% saving nationally – this was mainly in the industrial sector. The country has to focus on energy efficiency and demand-side management over the next five years to create the necessary power system buffers in the short term.* [Eskom, 2009c]

The PCP (Power Conservation Program), DSM and energy efficiency initiatives remain critical levers for demand management in the short to medium term, until the new power stations can commence generating electricity. [Eskom, 2009c]

Some DSM targets were provided:

Eskom DSM is working to effect a reduction of 3000MW by March 2011 (adjusted to March 2013 due to financial pressure on the company [Eskom, 2010a]) and a further 5 000MW by March 2026. This involves the installation of energy-efficient technologies to alter the load and demand profile of Eskom. These technical solutions are seen as hardwiring energy-efficiency measures which ensure a higher level of security of supply in the short to medium term. [Eskom, 2009c]

This implies that until more base load power stations are commissioned, energy conservation and energy efficiency across all TOU periods becomes the primary goal as this will reduce the need for load shedding throughout the day. Further measures that precipitate load shedding include Demand Market Participation (contracted customers are compensated for reducing load) and Interruptible Load (customer benefit from preferential tariffs but have to agree to reduce load when required by the utility). Controlling demand during Peak periods becomes a secondary goal (in the short term) as this only lasts for a total of 5 hours per day on weekdays.

With the specific mention of technical solutions, it is noticeable that TOU tariffs, and tariffs in general, are not being mentioned explicitly as part of DSM measures that will contribute to Eskom's DSM goals.

It is planned that more base load power stations will be commissioned by 2012 [Eskom, 2009c]. The South African supply problem would then be less due to a need for base load supply (and by implication energy efficiency and energy conservation) as opposed to peak load power stations. The classical time of day components of TOU tariffs would then be required to address the need to limit demand during the Peak periods to limit the use of expensive peaking power stations. Hence, limiting demand during Peak periods would then become the primary need again. For as long as the national demand pattern displays a residential tendency with peaks during the Peak periods, limiting demand during Peak periods will alternate between a primary need (when sufficient base load stations are available) and a secondary need (when there is a lack of base load power stations). The need for reducing demand during Peak periods thus becomes an ongoing need.

The South African need in terms of tariffs could be summarised into 3 broad categories:

1. Short term: Energy conservation to decrease the need for base load power stations.
2. Ongoing: Reduce the need to use expensive generation during Peak periods.
3. The need to define an appropriate energy mix, viz. peak, mid and base load power stations.

8.6 What are the options for the future

The residential customer segment appears to be one of the major contributors to the system having a peak demand during the High Demand Season as well as daily TOU Peak periods. Should there be a need to address the peak during the evening Peak period, the 2 major contributors were shown to be Rural Municipalities and Eskom's residential component. All residential customers (excluding any pilot TOU programmes), in South Africa are on a flat annual energy tariff or are exposed to an Inclining Block rate tariff (Eskom customers from 1 April 2010 onwards). As the rates are independent of time or year

They pay a flat energy rate regardless of time of day or time of year. They have no financial incentive to limit their usage during congested periods like the Peak period.

It appears that the South African government identified the *significant challenges* (with respect to domestic customers) *for utilities because of their large numbers and the many different types of domestic customers with diverse needs* [DME, 2008a]. Its official pricing policy position for the different types of domestic customers, *Policy Position: 36*

- *At the one end a single energy rate tariff with no basic charge, limited to 20 Amps and nominal connection charge...*
- *At the next level a tariff which could contain tariff charges to reflect a basic charge, capacity charge and energy charge with cost reflective connection charge...*
- *At the final level TOU tariffs must be instituted on the same basis as above, but with TOU energy rates.*

As an illustration of the typical costs that could be encountered, an estimate of the capital costs to implement TOU metering for residential customers was completed.

Certain assumptions were required to simplify the estimate in Table 8-7:

- A low voltage distribution kiosk is available to house TOU meter.
- Existing kiosks can accommodate on average 12 single phase customers. In existing areas, additional kiosks will be required to house larger TOU meter with up to 4 meters per kiosk (space requirement is greater to cater for additional hardware).

Meter costs (based on cost of existing TOU meter for LPUs)	2800
Cellular communication with appropriate interface	400
Kiosk adjustment to accommodate larger metering infrastructure or additional kiosks (with associated cabling)	500
Labour and Transport	500
Total	R 4,200

Table 8-7 Estimated costs for TOU metering

A 2008 Eskom study showed that the installation of a ripple control system would cost about R2300 per installation. In 2010 Rands, this equates to about R2600 when inflation (average of 6.5%) is included. A pilot study about the benefits of residential TOU tariffs in South Africa indicated a 0.8-1kW reduction during Peak periods when used in conjunction with a ripple control load management facility [Singh et al, 2006]. This equates to a R6800-R8500 per kW. To put these costs into perspective, and based only on capital costs, the cost of the proposed Kusile Power station was estimated at about R145bn for 4800MW capacity. This equates to R30,208 per kW.

A South African Government Gazette 3108 (Notice R.842) [DME, 2008b] with respect to The Electricity Regulations Act, 2006, appears to further support TOU tariffs. Pertinent points from the document include the following that is incumbent on the *licensee*:

- The installation of a *smart metering system* that is defined by TOU energy metering, two-way communication, data storage that can be accessed remotely, and remote load management.
- Load management could refer to pool pumps, hot water cylinders and air conditioning units.
- The load management system can only be used by the utility *during capacity or network constraint conditions*.
- Any other use must be preceded by communication to the end user.
- All *end users* that consume more than 500kWh⁸ per month must have this system installed and be operational by 1 January 2012.

⁸ At the time of printing. There has been speculation that this could change to 1000kWh.

The purpose of the smart metering installation would be:

“In order to maintain good quality of supply, ensure stability of the electricity network, minimise electricity load shedding and avoid blackouts,...”

It is noticeable that existing residential metering cannot accommodate the 2nd and 3rd categories of Policy Position: 36. The 2nd category indicates a *capacity charge* requirement while the 3rd requires TOU metering. One of the obstacles to more dynamic tariffs has been the prohibitive cost of metering relative to the income generated for the customer. It is not clear from Policy Position: 36 how this will be addressed.

These tariff proposals do not appear to have any apparent energy conservation or energy efficiency pricing signals for the residential segment (which was identified as short term needs in section 8.5) included for the residential segment. Only the more affluent residential customers would be exposed to a pricing signal that promotes non-peak consumption. This has the following, albeit conflicting, implications:

1. The government does not believe poorer residential customers are making a significant contribution to the problems the country is facing.
2. The government may suspect that poorer residential customers may play a significant role but may not want to be perceived to be penalising the poor for a commodity that is deemed a basic service.
3. As TOU tariffs are being proposed for higher consumption customers, only the more affluent residential customers are making a significant contribution to the peak demand. Hence, only they should be exposed to a pricing signal that promotes non-Peak period consumption.
4. In line with points 2 and 3 above, only the more affluent customers are penalised for Peak period consumption to compensate for the requirement that poorer residential customers should not be burdened with the additional cost.

8.6.1 Electrification

As Calitz [1989] stated, Electrification was one of the factors that would influence the load factor for demand. He also stated that one of the objectives of TOU tariffs was to improve the system LF. Eskom Electrification areas have the lowest weekly LF compared to other Eskom supplied residential areas and, to a lesser extent, in

conjunction with Eskom low income residential areas, seem to 'undo' the response displayed by other customer groupings.

A study by Howells et al [2005] considered the implication of FBE on the system profile. A survey prior to FBE implantation estimated that monthly usage was *typically about 20kWh* but that *traditional fuels* continued being used for cooking and heating. They indicated that the government initially set the FBE to 50kWh *so that it covers the electricity necessary for basic lighting, a small black and white television, a small radio, basic ironing and boiling of water using an electric kettle*. However, the availability of free electrical energy meant that the average overall consumption per household would increase the longer FBE was available. Households were purchasing and using electric cookers to use a portion of the FBE. These cookers were typically being used *when the electric power system is already stretched to its peak and the marginal cost of new services is at its highest* [Howells et al, 2005]. FBE thus indirectly contributes to the system demand, and more so, during Peak periods.

Similarly, as connection fees for new Electrification customers have been removed [Eskom, 2009d], access to electricity, and thus FBE, has been made easier that will further contribute to increased demand during Peak periods.

Bekker et al [2008] indicated that between 1991 and 2006 more than 5 million Electrification type household loads have been added to the grid by mainly Eskom and Local Government. They noted that the assumption during the 1990s and therefore planning was that 80% of households would be electrified by 2012. However, President Mbeki, in his State of the Nation address in 2004 said that *"...within the next eight years, ensure that each household has access to electricity"* [Mbeki, 2004] and this would be accomplished by Eskom and Local Government.

Even though Bekker et al [2008] deems that this is *practically impossible*, the Department of Mineral and Energy's initial target of 575000 connections per Annum for South Africa is still unchanged even though this has never been achieved.

Electrification Residential customers would most likely fall into the first category of *Policy Position: 36*. In Eskom's urban areas they would be supplied via a 20A supply and would

benefit from FBE that grants households 50kWh free per month. As to who qualifies for the special tariff: *Policy Position: 49*, customers on a 20A supply who consume less than 350kWh.

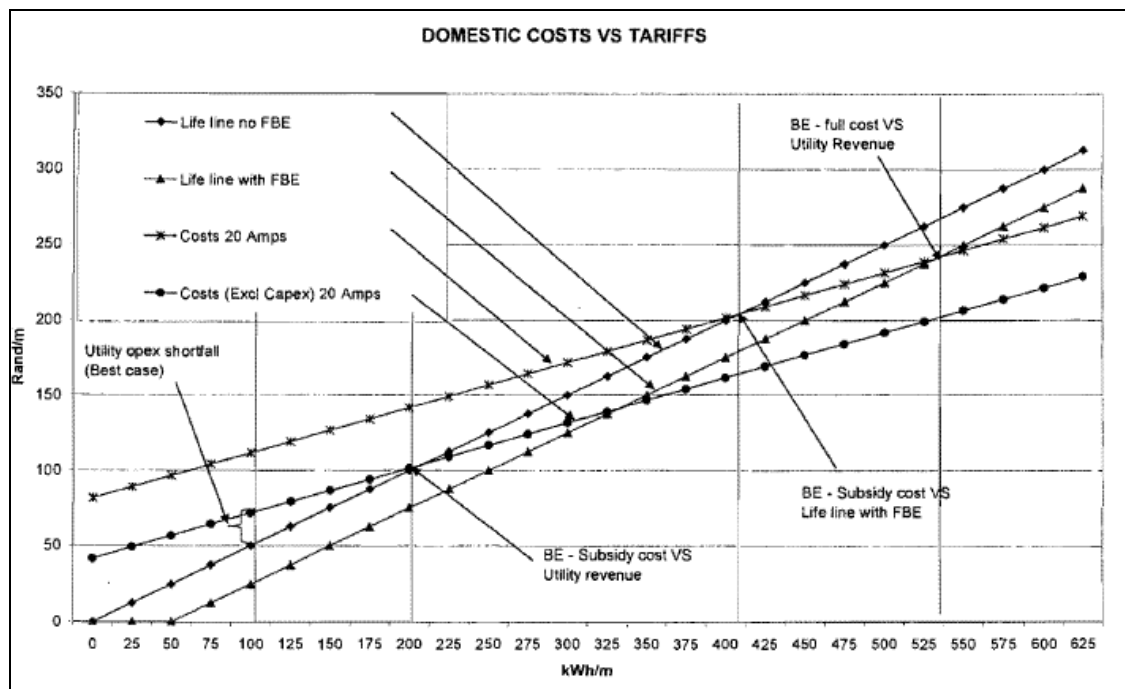
As this group is likely to consume less than 350kWh, they are not exposed to TOU tariffs or load management programmes. DME [2008a] stipulates that they should be supplied via a *single energy rate tariff*. Even if they were exposed to TOU tariffs, they might have *limited ability to shift load or to respond to signals* [Salvoldi, 2008; Singh, 2008]. It should be noted that these statements were not qualified in the respective literature and appears therefore untested.

DME [2008a] refers to a *Lifeline Tariff for Low Income customers* (here low income customers are equivalent to Electrification customers). They also state that *charging an appropriate tariff structure for maximum subsidisation at low consumption levels with gradually reducing cross-subsidies as the consumption level increases; and the granting of FBE. Policy Position: 50* states that *the impact of such cross-subsidy must be pooled over all customers in the licensee, not only domestic customers and should be shown transparently as a c/kWh levy on consumption* DME [2008a]. Further, it states a necessity that *tariffs cover only operating and maintenance costs*. The *breakeven point* is estimated to be 350kWh; thereafter the distribution utility would make a profit as illustrated by Figure 8-2. The 350kWh estimate is based on the assumption that the capital expenditure is not borne by the utility and that FBE is part of the Lifeline tariff.

This implies that the customers with the following characteristics:

- Who have the lowest LF,
- who peak when the system is under most duress,
- whose average energy consumption during the Peak period is the highest and thus incur the highest cost to the utility – from WEPS as a result of the use of OCGT and other peaking stations by Generation,
- who are cross-subsidised by other customers (for at least the first 350kWh)

is not deemed by government to be suitable for TOU tariffs as long as they consume small amounts. This could be justified by the intention of the electrification program as a social responsibility and a poverty alleviation tool as detailed in section 8.1 but it has been considered: what is the long term cost to the country?.



**Figure 8-2 Domestic Costs (Distribution Utility paying a WEPS rate) vs Tariffs
[DME, 2008a]**

With poverty alleviation in mind, if a TOU tariff were ever considered for the Electrification sector with the following provision and assumptions:

- while still retaining some sort of cross-subsidy (at least as a transitional measure while ensuring the required revenue to the utility as a the result of any potential under-recovery),
- assuming that Electrification customers do shift load from Peak periods,
- resulting in reduced demand during Peak periods,

the knock-on effect could result in reduced wholesale costs (WEPS) due to reduced Peak period costs and thus reduced cross-subsidisation leading to potentially lower electricity costs for all customers.

As government support for TOU tariffs for Electrification customers is not likely to be approved in the short term, other alternatives could be considered, including:

- Howells et al [2005] proposed an *energy credit* that is equivalent to FBE but can be used to acquire alternative energy sources like liquid petroleum gas that can be used for cooking.
- FBE to be limited to residential customers with at most a 20A supply with consideration for a maximum of 10A supply. This could persuade customers to reconsider electricity as a cooking energy source.
- Seasonal tariffs for residential customers with a higher rate being charged during the High Demand Season. The greater expense during the High Demand Season could provide some energy conservation benefits (due to price elasticity) that could ultimately reduce demand across all periods.

Anecdotal evidence suggests that richer customers are actually also benefiting from the cross-subsidisation. Residential customers who can afford solar heating installations as a hot water cylinder energy sources (or even as a swimming pool water heating facility) plus alternative cooking and space heating sources like liquid petroleum gas could ultimately reduce their reliance on electrical energy sources to such an extent to actually benefit from cross-subsidisation. Casual inspection of residential energy consumption data in Middle Income households confirms that there are many cases where the average monthly consumption is less than 350kWh. At the same time, a similar inspection of Electrification customers indicate that the average monthly consumption of about 1000kWh is not uncommon (however, this is more likely to be associated with secondary selling to close-by non-electrified households and/or backyard dwellers).

8.6.2 Low Income

Low Income Residential customers fall into the second category of *Policy Position: 36*. This housing group has a low LF for daily demand but would generally have most of the heating appliances one would find in Normal housing. Demand would be used to supply cooking and likely water heating load. Small space heating load would not be out of place. As their consumption is likely to be less than 500kWh, they fall outside the scope of the Government Notice R.842. As their daily demand is relatively 'peaky' a capacity charge would be ideal. This appears to have the support of the government's policy position. The cost of suitable metering could be a concern and needs to be investigated.

Alternatively, the Low Income Residential customer should have the choice if he wants to be metered at TOU rates. This should go a long way in ensuring that poorer customers are not excluded from a programme with potentially financial benefits.

8.6.3 Middle Income

Singh et al [2006] identified a correlation between residential geyser ownership and the 500kWh monthly consumption value. These households have been identified as the residential sector with the largest percentage of flexible load [Singh 2008].

Internationally, residential TOU tariffs have been available for many years and they have had considerable success. As prescribed in the Government Notice R.842, load management shall be installed to further enhance the utility's capability to control residential load. The customer has the option to control his consumption due to various signals (price or capacity) while the utility has the option to manage the customer's load should the customer response not be adequate (for capacity signals). Either way, customers benefit financially while the need for extensive load shedding is minimised.

As noted in Chapter 2, Faruqi [2007] indicated that the greatest response from residential customers occurs when TOU + CPP is coupled with enabling technology. Enabling technology refers to the ability for certain loads to be adjusted automatically when a CPP signal is received. An automated system could have a better chance of sustainable load reduction as manual *response fatigue* could set in after a period if load curtailment is the sole responsibility of the residential customer. Government Notice R.842 stipulates that customers should be notified before the load management option is utilised. However, if the customer chooses to have his load reduced by the utility during all Peak period times, all parties would benefit. Residential customer would gain financially while the utility would have reduced financial risk while also reducing Peak period load. Once again, this takes the responsibility away from the customer.

There is always the risk that utilities might not consider the additional *cost of metering financially viable* [Eskom, 2007] for customers to change their habits. However, as Faruqi [2007] noted, *Customer do shift load in respond to TOU price, even if the price signal is quite modest*. He was referring to a system where the price difference between

Peak and Off-peak was 30% and where about 300,000 residential customers were exposed to the TOU tariff.

8.6.4 Barriers to Residential TOU

As mentioned by Calitz[1989], one of the major challenges to further TOU implementation is that the bulk of residential customers are supplied by redistributors. Most Rural Municipalities in the Western Region are on the Megaflex tariff that does have an annual and daily TOU component. As the Megaflex tariff rates are fixed for generally 12 months (except 2008 where adjustments were made after 6 months), municipalities would be able to accurately forecast future expenses in terms of electrical energy purchased from Eskom. These costs could then be converted to a flat energy rate for their residential customers to ensure that (in the least) all costs are recovered. Importantly, there is no variable pricing to indicate the nature of the variable costs incurred by the municipality and hence the consumption pattern by the residential customers is not influenced by the tariffs. In view of the tariff (and metering) constraints, the municipality would have a simple goal of cost recovery and not necessarily load shaping.

When an overall solution is considered to Eskom's residential customers the list of options to address the problem is not extensive due to the economic diversity of residential customers. Ideally, residential customers should pay a TOU rate (as a minimum) as their peak consumption is at a time when the system is at its worst in terms of reserve capacity. Of all Eskom's residential customers it has been shown that Electrification and Low income households have the lowest daily load factors and have a considerable peak for a short time during the evening Peak period. This counters one of the intentions of the TOU tariff of trying to improve the system LF by moving demand from the Peak period by charging a more cost reflective rate during this period.

The obstacles to implement some form of TOU tariff on the residential component are many. As stated in section 8.1 the average increase granted to Eskom by Nersa amounted to 31.3% for the year ending March 2010, *Nersa also ruled that the price increase to "poor" residential customers be limited to 15%* [Eskom, 2009]. This implies that residential customers who are eligible for TOU tariffs that pay a rate that is more

cost reflective would also have to subsidise customers who benefit from reduced tariff increases and FBE.

It has been evident from Chapter 7 and subsequent discussions in this chapter, that poor residential customers are one of the significant contributors to the national capacity problem during evening Peak period. If a TOU tariff were ever considered for the residential sector, a change is required from the residential customer. For a change to happen a certain level of understanding of the tariff would be required to benefit from the change. This statement should be made in conjunction with the question: Would a TOU tariff be too complex for residential customers to understand?

There are several other commodities that charge an effective TOU rate. The one major example is cellular phone costs. There are various network providers who each have their own different charging system that is ultimately based on a TOU system. Cellular calls during telecommunication peak hours during weekdays would cost considerably more than the same call later in the evening or over weekends. This has been a concept that has been adopted and understood by most people who own cellular phones including customers in the Low Income and Electrification Residential category.

When poorer residential households are considered, variable cellular charges can be considered one of the better examples to which most people have already adapted to. The same pricing philosophy can be extended to the pricing of specific food items like meat that are generally more expensive around major religious holidays and adjacent holidays especially during the December period.

TOU philosophies could be considered part of people's lives already; it might not be called TOU and is not associated with electricity but there is a big enough response to warrant the continued existence of such pricing tools.

However, one of the stumbling blocks might be that they tend to have prepaid electricity meters that is not time interval based. Units of energy are bought and consumption occurs over all periods. If prepaid meters could be converted to reflect monetary value instead of number of energy units, TOU tariffs could practically be implemented in the prepaid market.

8.6.5 TOU Enhancements

Assuming TOU could be implemented with residential customers, and the existing TOU periods remain unchanged, if customers know that it costs less at 20h01 as the Peak period has passed, would more residential customers suddenly switch more load back on that might cause a surge not only on the greater distribution system, but possibly overloading and tripping the local reticulation network? It has already been shown that certain groups of LPU's that are not residentially orientated increase their load after the evening Peak period in an apparent response to price. Assuming further that the residential customers that are supplied by the municipalities are also on a TOU tariff, and start responding to pricing signals, the system could be under severe pressure, possibly even more so than without TOU tariffs during the adjacent Standard period.

Some form of further load management in conjunction with the standard TOU tariff could be considered as a solution where the utility has some form of control over the comeback load after an expensive Peak period where load was limited. One example could be a load management system on the flexible portion of the residential load that is more likely to be found in Middle Income homes. This could include hot water cylinders, pool pumps and air conditioners. However, this could mean that hot water cylinders could be off for extended periods after the Peak period which could ultimately negatively affect the customer acceptance of the facility.

The advantage of having both facilities will aid two causes. The first will be that residential customers would have the benefit of controlling the bulk of their own load in response to price. Secondly, the utility will have comfort knowing that if there were not sufficient response from the residential customers as a group, load management on the flexible residential load can be implemented. In addition, the utility would have the benefit of the load management system when unplanned supply side conditions affect the stability of the system. The *smart metering* system that was mentioned earlier appears to be able to perform these different functions.

Importantly, Electrification or Low Income households are not likely to consume more than 500kWh (criteria for smart metering) and would at this stage be excluded.

8.7 Nersa

Nersa interacts with Eskom and municipalities in a different manner and will be discussed separately.

Nersa reports to the Department of Energy (DE) within government and together determine the policies and guidelines that regulate the electricity supply industry. Municipalities report to the specific department in government, Department of Provincial Local Government (DPLG) and adhere to the Municipal Finance Management Act. Eskom reports to the Department of Public Enterprises (DPE) and adheres to the Public Finance Management Act.

The impact of the difference is illustrated by the following example:

In terms of Section 42 of the Municipal Finance Management Act (MFMA) Eskom can only apply increases to the local authority tariffs on 1 July each year. However, Eskom's revenue requirement is recovered over its financial year, which is from 1 April to 31 March each year. This means that the local authority tariffs are increased later than other tariffs. Therefore, for three months they pay less than the approved increase and for nine months higher, but on average over 12 months, they will see the overall average increase. [Eskom, 2008d]

Therefore, within government, there are at least three separate government departments that are involved in the electricity supply industry and the different utilities operate on different financial principles.

8.7.1 Municipalities and Nersa

The role of Nersa can be summarised by:

"...introducing efficient and effective regulation of the electricity supply industry in South Africa in line with Government policy and law. It would perform this function by issuing licences to generators, transmitters and distributors of electricity and require licensees to comply with its directives on quality of supply and service, tariff determination and reporting, among others." [AMEU, 2006]

However, in the same statement, the following is highlighted:

“Enforcement of compliance: Many municipalities either do not have the resources to provide the information required by the NERSA or believe that municipal legislation provides them with necessary powers to ignore NERSA's requests and directives. A prime example is the setting of tariffs where a number of municipalities implement tariffs that have specifically not been approved by NERSA. The only sanction NERSA could possibly use is withdrawal of a licence but this would be in all probability be contested by the offending municipality based on its constitutional authority over 'reticulation'.”

And further:

“Of the 177 municipalities supplying electricity, 60 (42%) have illegal tariffs (tariffs that are not formally approved by the NER and which are thus in breach of the Electricity Act).” [Competition Commission, 2006]

It would seem that Nersa's requests and directives are not being adhered to by all the licensees who supply the bulk of South Africa's customers. On the surface this might seem an obstacle should Nersa want to enforce their compulsory smart metering system for end users who consume more than 500kWh or any other Nersa directive on tariff structures.

Tariff increases are being implemented within municipal supply areas without necessarily obtaining Nersa approval. This allows these licensees the opportunity to implement more dynamic tariffs without the perceived delays that may be associated with external regulatory tariff approval. It is not clear how the Rural Municipalities, as a group, benefit from this *opportunity* and apparent regulatory oversight as their collective profile still shows a distinct peak during the Peak periods.

8.7.2 Eskom and Nersa

Eskom, government owned but reporting to DPE, must adhere to Nersa's requests and directives. The Eskom tariff approval process does appear to include a lengthy internal approval process before consideration for Nersa presentation. Within Eskom, structural changes will firstly go through an internal approval process that may take 6-12 months.

Once internally approved, this proposal then needs to be finalised for Nersa consideration which happens by December of each year. Generally, Nersa gives official feedback by the end of March for Eskom to implement by 1 April in Eskom supply areas.

This means that after the December submission, Eskom can start working (the subsequent January) on proposals for the following year. As the new proposal would only be considered the following January (now 12 months later) and implemented by 1 April, a total of 15 months is considered the general timeframe to get new proposals approved and implemented.

Therefore, if tariffs were dynamic enough to cater for supply side problems, the problem might have adopted different dimensions by the time that the tariff is finally approved, which could make the initial proposals out of date. The issue that arises from this paragraph is whether tariffs should be used to address system problems.

Nersa is a government appointed body under the auspices of DE while Eskom reports to DPE. There is a public perception that there are differences between the two Ministries as one government Ministry is effectively applying to another for tariff approval. The public perception is acknowledged by government (but refuted) by the following official government statement on 25 June 2009 with respect of tariff increases granted in 2009: *“Several articles have appeared in the past two days (23-24 June 2009), citing a supposed difference of opinion between the two Ministries on the tariff increases. There is no difference of opinion in Cabinet over this issue, and the Budget Vote speeches tabled in Parliament this week by both ministers were clear on the matter.”*

[South African Government, 2009]

Eskom makes three pricing submissions to Nersa for annual approval. Eskom's Generation, Transmission and Distribution divisions make separate submissions as the three divisions are *financially ringfenced and regulated separately* [Eskom, 2008a]. Is there an official policy where it is instructed that the three divisions are not allowed to consult to each other before pricing submissions are made? It would appear that way as no formal communication forum seems to be available for these discussions to take place.

If the retail market response could be fed back to the wholesale market where ultimately prices are determined for the industry, the process would have a more comprehensive cause and effect model that will aid in determining a more 'ideal' wholesale price that will eventually be transferred to the retail market.

If the individual pricing departments were to share information pricing submissions can only be strengthened for Nersa consideration.

8.8 The 'Ideal' Tariff customer relationship

In an 'ideal' relationship tariffs should be a flexible tool that can respond to customer reactions.

'In the beginning' a new tariff is introduced that is 'mostly' representative of the present generation mix (base load stations, peaking stations etc.), will ensure adequate revenue recovery and is effective for 12 months. Customers (Retail and Wholesale) analyse the tariff and determine the most effective consumption pattern that will give them the maximum operational and financial benefit. Over the 12 month period, customers slowly adjust their consumption patterns until they have achieved the maximum benefit from the tariff. The utility notices the change in consumption from the customers; over the 12 months, the utility has also been busy with a study to determine the optimal medium to long term – 10 to 25 years - generation mix, both from an operational and financial perspective.

The utility recognises that the tariffs – excluding at least poorer residential tariffs - have to move towards the marginal cost of the generation mix that will be present in the medium to long term. Tariffs are adjusted by the utility in view of the future generation mix and again the customers respond to the pricing signal by adjusting their consumption patterns.

This process repeats itself annually until the pricing signal provided by the tariffs is a 'perfect reflection' of the generation mix and customers have attained the maximum benefit from the tariff.

An interview with Marais Roos [2009] who was instrumental in the original WEPS tariff revealed a similar vision as illustrated in the ideal tariff customer relationship. He indicated that tariffs were not intended to be a static entity but something that would change in reaction to customers' response while customers would continuously be adjusting their consumption patterns in response to tariffs. Ultimately, the tariff customer relationship would always be moving towards the perfect balance between pricing signals (that are reflective of the generation mix) and customer response.

Practically, the WEPS tariff was implemented, and the associated TOU signal was transferred to Retail tariffs. Retailers customer responded by adjusting their consumption patterns; however, the overall structure of the WEPS tariff remained rigid and customers responded to the same rigid pricing signal. Customers have been responding annually with no counter response from the tariffs to balance the relationship. Hence, the perceived 'disconnect' between tariffs and customer response remains.

9. Review of TOU tariffs' goals

This chapter will discuss whether the intentions of Calitz were in fact realised. However, it will also critically evaluate whether his reasoning is still valid in 2009.

Calitz [1989] focussed on load shifting and peak clipping in his report. He emphasised the need for DSM programmes at a time of surplus capacity in Eskom due to:

- *Sharp recent and future increases in the cost of new generating capacity, together with the need to conserve capital and protect the South African balance of payments*
- *...natural reduction in system load factors of demand.*
- *The need to keep electricity price at affordable levels by increasing the utilisation of Eskom's generating capacity.*

Calitz [1989]

The need for TOU tariffs was illustrated by:

TOU pricing is the most effective DSM tool to achieve load shifting by customers, and to convey to customers the time-varying nature of Eskom cost of electricity supply. [Calitz, 1989]

Calitz [1989] noted that some the objectives of TOU pricing include increasing the load factor by peak clipping and load shifting measures. His goal included:

- Shift load from the times of highest fuel costs to off-peak periods that are characterised by lower fuel costs.
- Conserve capacity.
- Improve load factor

As most of the data relates to the Western Region, Calitz's intentions will be compared to the Western Region customers. Nationally, system data is available for selected aspects that will be evaluated accordingly.

9.1 Are the needs still the same?

9.1.1 Cost of additional generating capacity

The high cost of generation is probably more relevant today than when Calitz referred to it in 1989. Therefore, this need is still very relevant as one considers the utility's Multi Year Pricing Determination of Eskom of 24.8% per annum for three years starting July 2010. Part of the justification used by the utility is the need to fund their R385bn power expansion programme [Mining Weekly, 2009]. The utility indicated that that it has three sources of funding [Eskom, 2009e]:

- *The shareholder has made available a R60 billion subordinated loan, which has the characteristics of equity. The loan will be drawn over three years as follows: R10 billion in 2008/9; R30 billion in 2009/10; and R20 billion in 2010/11.*
- *Debt: Limited by its credit rating, it estimates it can raise up to R40bn per year*
- *Regulated revenue and tariffs: These are relied upon by Eskom and providers of capital to earn returns on capital investment over the longer term, and would need to be sufficient to satisfy the requirements of both debt and equity providers.*

The utility further argues that *the higher the regulated tariff, the stronger the equity position, the more likely it is for Eskom to raise substantial debt funding at a reasonable cost* [Eskom, 2009e].

It becomes difficult to operate as a *viable concern*, especially in the future if revenues are not sufficient. While surplus capacity was available, regulator approved tariffs effectively decreased in real terms and did not appear to cater appropriately for long term investment in generation capacity.

... it is essential that an efficient and prudent licensee should be able to generate sufficient revenues that would allow it to operate as a viable concern now and in the future. [DME. 2008a]

Some of the factors affecting the revenue requirement is the depreciation cost of existing assets and inflationary cost of new assets. *However, when there is a major discrepancy between asset values used for regulatory tariff setting and new asset values, it creates a potential funding shortfall when new assets are introduced* [DME. 2008a].

As South Africa's reserve margins need to be increased to *acceptable levels* and to cater for economic growth, new generation capacity is required, now and in the future. The utility argues that new generation capacity should be funded in part by increased tariffs and, by implication, debt due to perceived improved financial well-being. The Electricity Pricing Policy (EPP) appears to support this philosophy:

Tariffs, therefore, need to be set at a level which would not only ensure that the utility generates sufficient revenues to cover the full costs (including a reasonable margin or return) but would also allow the utility to obtain reasonably priced funding on a forward looking basis [DME. 2008a]

The government's EPP states that there is *wide support for the publication of a long term price outlook (at least 10 years). Ideally the forecast should show the contribution of generation, transmission and distribution to the forecast price level...* [DME. 2008a] Considering that generation capacity is an ongoing concern, the price outlook could always cater for future capacity requirements.

The cost of additional generating capacity has an impact on the cost to the consumer via increased tariffs; hence if this can be minimised, the consumer, and ultimately the economy, benefits financially. Calitz's issue was relevant in 1989, and the EPP makes it still relevant in 2010.

9.1.2 Reduction in system load factor for demand

The Integrated System Load Factor was plotted as shown in Figure 9-1. Calitz [1989] noted that the annual system load factor was comparatively high by international standards for the years 1986-1988 ranging from 74-77%. He noted that EdF's was only 60% in comparison. However, he indicated that South Africa's load factor was high due to the then *present low levels of domestic electricity consumption in South Africa, accompanied by a mild climate.*

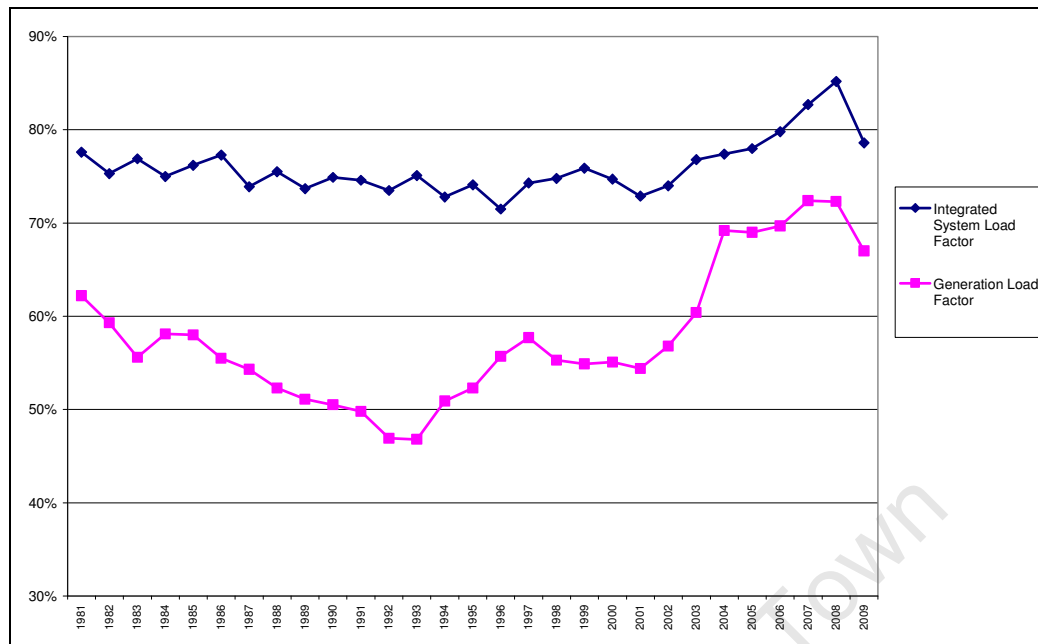


Figure 9-1 National Load Factors

As shown in Figure 9-1, the Integrated System Load Factor^{9,10} was in decline from 1982 to 1996. At this point, Calitz' concern about declining load factors had proved valid. Subsequently, there was an increasing Load Factor until 1999 before decreasing until 2001. Thereafter, the Load Factor was increasing until 2008 before a fall in 2009. It is noticeable how the gap between the Integrated System Load Factor and the Generation Load Factor has decreased from about 1993 onwards. This is a further indication of the declining reserve margin. The increasing gap between the profiles prior to 1993 is an indication of the surplus capacity at the time.

As Calitz [1989] stated, Electrification was one of the factors that would influence the load factor for demand. He also stated that one of the objectives of TOU tariffs was to improve the system LF. Eskom Electrification areas have the lowest LF compared to other Eskom supplied residential areas and, to a lesser extent, in conjunction with Eskom low income residential areas, seem to 'undo' the response displayed by other

⁹ The Integrated System Load factor is defined as kWh produced times 100 divided by maximum system demand time hours in the year

¹⁰ The Generation Load factor is defined in Eskom's various Annual Report as *kWh produced times 100 divided by average net maximum capacity times hours in year* [Eskom, 2003].

customer groupings. Calitz [1989] predicted a declining load factor with electrification load being one of the major contributors:

Increasing urbanization and future electrification of townships will undoubtedly decrease Eskom load factors of demand. [Calitz, 1989]

The national electrification statistics is shown in Table 9-1.

	<i>Eskom connections</i>	<i>Local govt connections</i>	<i>Off-grid connections</i>	<i>Farm workers connected</i>	<i>Total household connections for period</i>	<i>Calculated cumulative household connections, including farm workers and off-grid (calculated)</i>
1 Jan 1990	—	—	—	—	—	2 998 897 ¹
Jan91 - Dec91	31 035	51 435	0	0	82 470	3 081 367
Jan92 - Dec92	145 522	74 335	0	12 689	232 555	3 313 922
Jan93 - Dec93	208 801	107 034	0	16 074	331 909	3 645 831
Jan94 - Dec94	254 385	164 635	0	16 838	435 858	4 081 689
Jan95 - Dec95	313 179	150 454	0	15 134	478 767	4 560 456
Jan96 - Dec96	307 047	137 534	0	9 414	453 995	5 014 451
Jan97 - Dec97	274 345	213 768	0	11 198	499 311	5 513 762
Jan98 - Dec98	280 977	136 074	0	10 375	427 426	5 941 188
Jan99 - Dec99	293 006	144 043	0	6 241	443 290	6 384 478
Jan00 - Dec00	250 801	139 780	0	6 438	397 019	6 781 497
Jan01 - Dec01	206 103	127 255	0	3 560	336 918	7 118 415
Jan02 - Dec02	209 056	124 961	1 736	2 819	338 572	7 456 987
Jan03 - Dec03	173 094	88 149	15 156	2 363	278 762	7 735 749
Apr03 - Mar04	—	56 799 [#]	18 092 [#]	—	258 000 or	7 800 249* (Est. 230 967 [#] 264 500 new connections 1 Jan to 31 Mar 2004)
Jan04 - Mar05	219 885 [#]	—	—	2 429 [#]	—	—
Apr04 - Mar05	—	217 287 ^{# 3}	6 146	—	232 287 or	—
217 287 ^{# 4}	8 032,536 [*]	—	—	—	—	—
Apr05 - Mar06	135 903	—	20 842	1 105	172 139	8 204 675*
Apr06 - Mar07	151 088	—	—	1 037	155 476 ⁵	8 360 151*
Notes						
Notes						
<i>Italic text indicates overlapping periods.</i>						

Table 9-1 Reported Electrification connections [Marquard et al, 2007]

South Africa's electrification connection rate shows an increasing trend in the number of connections from 1991 to 1997 with a peak rate of close to 500,000 in 1997. The rate averaged about 466,000 connections per annum from 1994 to 1997. The rate decreased from 1998 to 2000 but still hovered around the 420,000 mark. From 2001 to 2005 the rate decreases significantly to an average of about 276,000. From 2005 to 2007 the rate decreased further to about 163,000 connections per annum.

There appears to be a correlation between the high rates of electrification during the 1990's and the declining load factor for the same period.

During the 1990s Eskom was experiencing surplus capacity issues due to over-investment in capacity during the 1980s that led to:

Older plant (about 5000MW) was decommissioned or mothballed. Previous demand growth projections were scaled back. Nevertheless, maximum generating capacity still exceeded peak demand by 63% in 1992. Eskom began to promote load growth through low-cost electricity contracts to energy-intensive users including new export-orientated minerals-beneficiation investments in aluminium and ferrochrome. [Eberhard, 2003]

And still later:

Electricity utility Eskom is developing new business opportunities and foreign investment through the investigation of opportunities for electricity-intensive industries in South Africa, which has the lowest-priced electricity in the world [Engineering News, 1999].

There appears to be a further correlation between the increase in load factor in 1997 and the timing of major industrial customers like electricity intensive industries like smelters (Richards Bay, Maputo) coming online from 1996 onwards. Eskom was contracted to supply a total of 2150MW to the three aluminium smelters [Miningmx, 2008].

When one considers the country's Gross Domestic Product in Figure 9-2, it is evident that the period from 1998 onwards shows an upward trend that implies that the economic situation of the country as a whole is improving. This could very likely include some of the older Electrification areas' residents would have acquired more electrical appliances that would coincide with increased load factor, as well as the general business community.

From 2001 onwards there appears to be a correlation between a decreasing rate of electrification, pursuit of new electricity intensive industries, improving economic conditions and an increasing load factor. Between October 2007 and February 2008 Eskom implemented extensive load shedding, which was pre-empted by demand market participation programs to encourage larger industrial customers to reduce demand. Further DMP initiatives and less frequent load shedding occurred for the remainder of

2008. This would have contributed to reduced demand leading to an improved load factor which may explain the relatively sharp increase in load factor for 2007 and 2008.

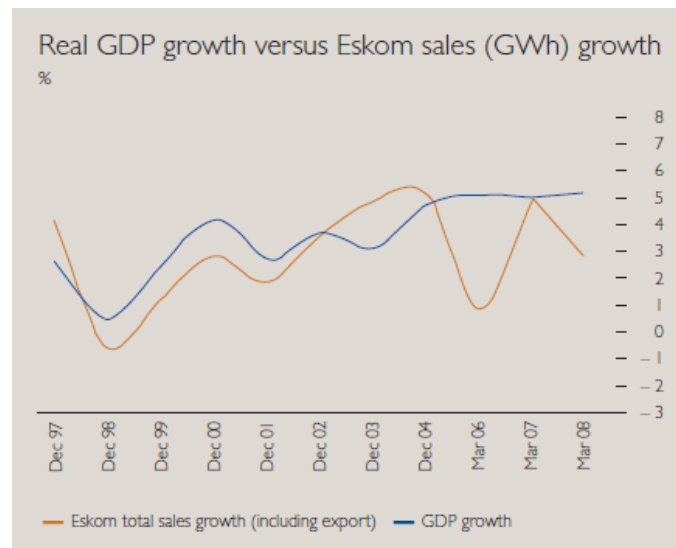


Figure 9-2 South African Growth Domestic Product vs Eskom Sales growth [Eskom, 2008]

The decline of the system integrated load factor in 2009 can be attributed to the global economic downturn that led to reduced demand from the local steel industry, followed by the ferro-alloys sector [Eskom AR 2009]. The generation load factor decreased as a result of new generation coming online (several OCGT power stations) and reduced demand. In addition, the 2009 value includes periods of 2008 that necessitated regular load shedding, including requesting major industry like those related to mining and the petro-chemical industry to stay offline for extended periods to ensure that the majority of South African customers would be minimally affected by required load shedding.

In summary, it appears that, during the 1990s, there was a definite decrease in the system load factor. Notwithstanding the fall in 2009 due to the global economic downturn, from 2001 to 2008, the LF has been increasing consistently. However, Bekker et al [2008] estimated that between 64% and 80% (derived from various sources of published data) of the households in the country have been electrified. They estimated that a further 6.9 million households (majority in the rural areas) would need to be electrified to achieve universal access. This means that more low LF load still needs to

be supplied that could put downward pressure on the system load factor. Therefore, this implies that an increasing load factor is still relevant today as it was when Calitz mentioned it in 1989.

9.1.3 Need to keep electricity prices affordable

A very delicate balancing act is generally required between the ability of a utility to have sufficient capacity available and being able to keep prices affordable.

The utility needs to be able to access debt to construct new generation capacity. To achieve this, they need to finance the debt via increased tariffs while, at the same time, keep prices affordable.

In South Africa (but not limited to this country), the issue is further complicated with the need that certain sectors of customer groups should be protected from high prices. Even though there is a strong correlation between the low load factor load profile of residential customers and the national demand profile, especially during evening Peak periods, these customers are not charged for the high marginal costs incurred at that time (at least not for the first 350kWh). Therefore, Electrification and Low Income (with low consumption) residential customers are protected with lesser tariff increases as opposed to the rest of the customer groupings. This means that other customer groups need to subsidise these customers that puts further pressure on a utility that strives to keep prices affordable.

The regulator that approves tariff applications is faced with a different set of challenges. Their balancing act includes the need for cross subsidisation by businesses of residential consumers while also striving to keep prices affordable that will support an environment for economic growth. In addition, allowance has to be made for an environmental levy on non-renewable generation.

Keeping prices affordable is as relevant today as when it was mentioned by Calitz in 1989. However, it appears that Eskom approved tariffs are being kept affordable to only poor residential customers as their increases are less than the average increase to other customers [Nersa, 2009, 2009a]. As stated earlier, this implies cross-subsidisation is

required to compensate for any revenue shortfall to the utility. However, at what cost to the country is this being done?

If too many resources are allocated to alleviating poverty, the economic capacity of the country and its sustainable support of the social action can be crippled, leading to external intervention in national affairs by creditors. So, in the extreme, an electrification programme may have significant negative impact on a utility, government and economy as a whole, particularly if the performance is not as good as predicted, as has been the result of many electrification programmes. [Gaunt, 2003]

DME has stated in its Electricity Pricing Policy that:

Cost reflective tariffs are the most effective pricing signal to be provided to customers [DME, 2008a].

However, due to cross-subsidisation cost reflective tariffs are not being charged for poor residential customers (at least for the first 350kWh). Electricity to the poor could be viewed as a poverty alleviation facility and part of government's social development responsibility. It should be acknowledged that electrification investment *may give neither financial nor economic return, and can only be justified for other reasons, basically for an ethical obligation or political gain.* [Gaunt, 2003]

Cross-subsidisation appears to be inevitable to ensure that tariffs to the poor remain affordable. However, anecdotal evidence suggests that the subsidy base (like richer residential customers) may be considering or have already converted to alternative energy sources like liquid petroleum gas (for cooking or space heating) or renewable sources like solar power (water heating). Larger industrial customers (large mining groups) may also consider self generation [De Lange, 2010] which could further erode the subsidy base.

This study has shown that there is strong correlation between residential peak demand and system peak demand, and that customers (except redistributors who resell to residential customers) who are exposed to TOU tariffs appear to respond to the pricing signals. Howell et al [2005] have shown that FBE could contribute to system peak demand. Tariffs have an impact on system demand: TOU tariffs may reduce peak demand while FBE may contribute to peak demand.

Keeping tariffs affordable for some by 'undercharging' while overcharging others to compensate for the revenue shortfall, may have sustainability concerns. This implies that cross-subsidisation may have sustainability issues that need to be considered when the long term pricing outlook is submitted by the utility to be evaluated by Nersa.

9.2 Load shifting from Peak periods

9.2.1 Has Load shifting occurred?

From a regional perspective there has been evidence suggesting that there is a definite preference by the different groups of LPU's for the Standard and Off-peak periods relative to the Peak period (sections 7.4 - 7.6). This correlates with the lesser costs of the Standard and Off-peak periods. From a seasonal perspective, there has been a similar preference for the cheaper Low Demand season to the expensive High Demand season (sections 6.3 – 6.5) but relatively less significant. In both cases, LPU's with a significant residential customer component have not been able to make as big a change in shifting from the expensive daily periods nor the annual High Demand season.

As the bulk of the country's residential customers are on a flat tariff, these customers have not been given a pricing signal to change their consumption patterns. Therefore, over the respective study periods, customers who do have more homogeneous load in terms of consumption patterns and have been exposed to TOU tariffs do seem to avoid the expensive rates of the High Demand Season on an annual basis while also showing a preference for the cheaper periods during the day. In order to fully test whether this response was due to the pricing signals by TOU tariffs one would need the same consumption data prior to the implementation of TOU tariffs. Unfortunately, as this particular data resource is not accessible to the author, questions remain about the full effectiveness of TOU tariffs in relation to flat tariffs.

From an annual perspective the exceptions remain CCT and the Rural Municipalities who have significant residential components. From a daily perspective, CCT appear to be managing their evening Peak load while Rural Municipalities have not been as successful.

An attempt was made to illustrate the changes that have developed since 1985 to the national system demand pattern. If any load shifting did occur nationally, the changes could be evident if the profiles prior to TOU tariffs were considered. At the same time, if the residential segment were making a difference to the profile, some evidence might present itself. Eskom's Statistical Yearbooks and Annual Reports since 1985 were studied to determine the changes that have occurred to the national demand pattern. It was shown in Chapter 3 that the national demand pattern indicate 2 peaks, one during the morning Peak period and the other during the evening Peak period. The values for the 2 peaks for the peak day of the year were recorded from 1985 to 2008 and plotted in Figure 9-3. Note that the literature only quantifies the peak value for that day; thus e.g. if the peak occurred during the morning this value would be available in the literature but the evening peak was estimated. The estimated values were not accurate but were meant to illustrate the changes that have occurred since 1985.

Findings from Figure 9-3:

- In 1992 the system peak changed from a Morning Peak to an Evening Peak during the specific Peak periods.
- The gap between the Morning Peak and Evening Peak profiles appear to be widening.
- The trend line for the Evening Peak illustrates a faster growth rate than the Morning Peak trend line. This implies that the Morning Peak has increased at a slower rate than the Evening Peak.

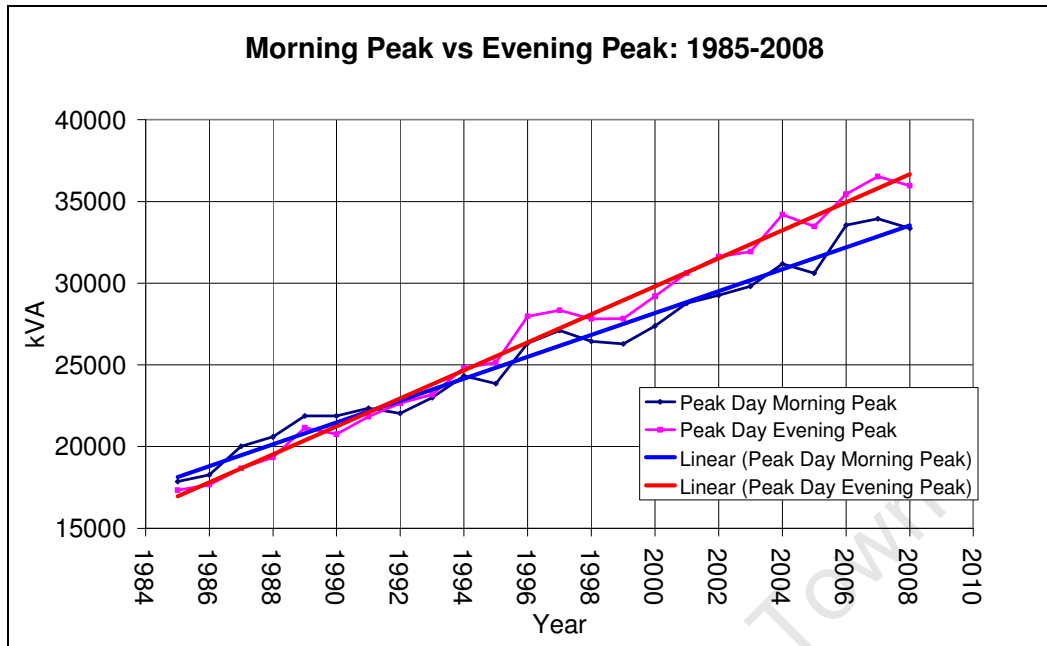


Figure 9-3 Peak day, Morning Peak vs Evening Peak: 1985-2008

It was shown in Chapter 7 that LPUs without a significant residential component appear to avoid the Peak period by registering higher Average half-hourly indices for either the Standard or Off-peak period. The sample of Eskom's residential customers profiles illustrated a tendency to use more energy during the Peak periods. Specifically, Electrification (and to a lesser extent Low Income customers) had the lowest LF with the highest Maximum and Average half hourly indices during the Peak period (specifically the evening Peak period) compared to a much lower morning peak. Electrification customers also registered the highest Maximum half-hourly index which is an indication of the extreme 'peakiness' of its profile, and by implication, the lowest LF.

For the sake of discussion, assume that LPUs in the rest of the country have similar profiles to those in the Western Region and that there are similar correlations to the tariffs. Further, assume that residential customers across the country have similar profiles as those in the Western Region.

Electrification customers' contribution to the Morning Peak profile is much less significant compared to the Evening Peak profile from a national demand pattern perspective. Hence, the TOU gains from LPUs (reducing demand during the morning Peak period or

shifting demand to the Standard period) correlates to the lesser growth in the Morning Peak profile in Figure 9-3.

Conversely, as Electrification customers' contribution to the Evening Peak profile is much more significant the TOU gains from LPUs appear to have been 'nullified' and appear to have been surpassed (relative to the Morning Peak profile). This correlates to a faster growth rate for the Evening Peak profile in Figure 9-3.

Figure 9-3 has shown that the Morning Peak profile was exceeded in 1992 and remained less than the Evening Peak profile for the rest of the study period. The gap between the 2 profiles appears to be increasing as shown in Figure 9-4.

This implies that the apparent load shifting from the morning Peak period may have been more successful than from the evening Peak period. This correlates further to the profile of residential customers, and specifically Electrification customers.

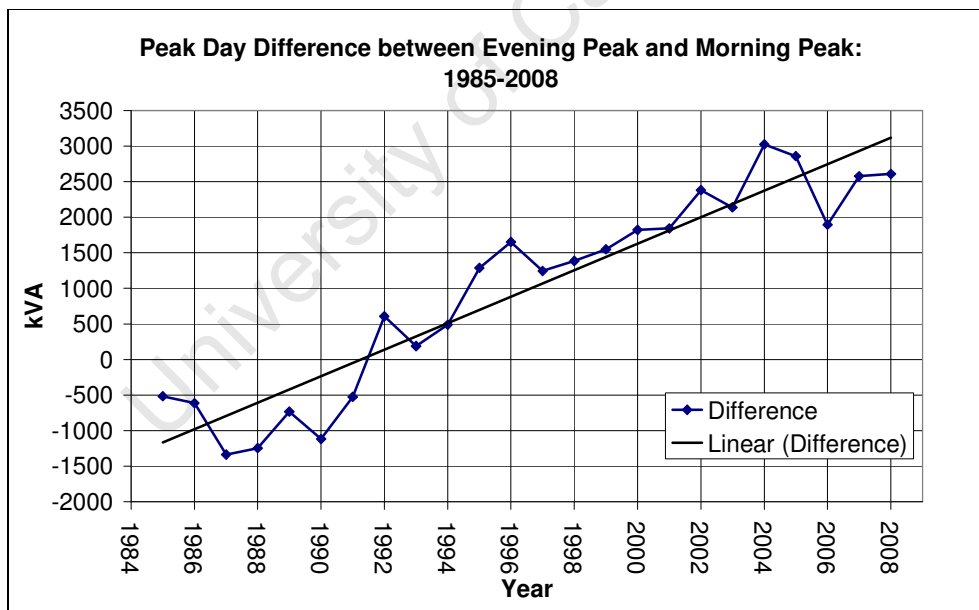


Figure 9-4 Difference between Evening Peak and Morning Peak: 1985-2008

9.2.2 Is load shifting still a requirement?

Capacity problems were evident throughout the day during the load shedding incidents of early 2008 and not only limited to Peak periods. There seemed to be greater

emphasis on energy conservation across all periods rather than load shifting. While energy conservation certainly has long term merit load shifting from Peak periods will remain a requirement. When adequate generation capacity is eventually commissioned in South Africa, the characteristics – Peak period peaks - of a residentially influenced demand profile will still be present. With millions of Electrification customers still to be connected, there might be more of a residential component during the evening Peak period. Capacity problems might then be restricted to Peak periods only with the most cost effective solution not necessarily being supply side orientated. A demand side solution will be more cost effective and certainly less time dependant compared to most supply side options.

9.3 Capacity Conservation

9.3.1 Has Capacity Conservation occurred?

Nationally, the daily and annual profiles still display a significant residential influence. However, the daily profile has shown significant changes for the period 1985 – 2008 as summarised in Figure 9-3.

During the late Eighties the Typical Winter Day morning peak is equivalent and even exceeding the evening peak. During the early Nineties the evening peak starts to exceed the morning peak, while from the late Nineties until 2008 the evening peak clearly exceeds the morning peak.

From a capacity perspective it appears as if the morning peak has been 'flattened' in relation to the evening peak throughout the year. An alternative way of describing this is to say that the evening peak has 'grown' faster in relation to the morning peak as summarised in Figure 9-3 resulting in an ever increasing difference between the two peaks as shown in Figure 9-4. This suggests that capacity conservation may have been more effective during the morning Peak period.

As mentioned in section 9.2 two possible factors could have contributed to the changing national demand patterns since 1986, viz. the impact of TOU tariffs and Electrification. While there are correlations between the average demand of LPU's on TOU tariffs

(excluding municipal LPU's) and the costs of the different pricing periods (especially the Peak period), Electrification customers' profile shows a sharp peak during the evening Peak period. There appears to be a correlation of the residential profile (especially the Electrification profile) and the increasing difference between the Morning Peak and Evening Peak profiles in Figure 9-4. With millions more Electrification households to be connected, this implies greater demand during the evening Peak period and increased capacity challenges.

If one considers Figure 9-3, the demand for 2008 is less than 2007. In addition, the 2009 reading (not shown) is even lesser than 2008. This may be more a result of load shedding, the global economic recession that led to decreasing growth figures.

If there were a definite shift from LPU's from the expensive Peak period to the less expensive Standard and Off-peak periods, it would be fair to assume that a measure of capacity reduction would inherently occur during the Peak period as well. As the national profile reflects a strong residential correlation that is characterised by highest demand during Peak periods, the capacity problems appear most evident during these periods. Therefore, when energy shift occurs from the Peak periods, a measure of capacity reduction, and hence capacity conservation, would be expected as well.

9.3.2 Is Capacity conservation still required?

Adding new generation capacity is very capital intensive. Generation with higher capital costs (e.g. nuclear) tends to have lower operation costs while generation with lower capital costs (e.g. OCGT) tends to have higher operational costs. Capital and operational costs impact the long term marginal cost of electricity which ultimately affects the average prices charged to customers.

In order to keep the long term marginal costs to a minimum the choice of technology for new generation becomes crucial. If capacity conservation is not addressed continuously, there will be earlier needs for new generation capacity which tends to put upward pressure on average prices.

Increased residential load implies a greater need for capacity during the Peak period. In the short term this means increased utilisation of the expensive peaking stations like OCGT; in the long term, the alternative is more capital intensive base load power stations to be used to minimise the use of peaking stations. In both scenarios, this contributes to increased costs of the long run marginal costs of energy that implies higher average costs. This implies increased tendencies to consider alternative energy sources and self generation implying further erosion of the subsidy base that ultimately implies increased costs for all.

Therefore, as when Calitz mentioned capacity conservation in 1989, the issue cannot be excluded from ongoing strategies.

9.4 Improving Load factor

9.4.1 Has the Load factor improved?

The Integrated System LF indicated a decrease during the 1990's with a subsequent increase from 2001 onwards (Figure 9-1).

There appears to be a correlation between the decreasing LF and the high rate of Electrification during the 1990's. However, during the pursuit of more energy intensive business due to perceived excess capacity, a favourable economic climate and the declining rate of Electrification there appeared to be a correlation to the increasing LF from 2001 onwards.

One of Calitz's goals was to increase the system LF via tariffs. Due to data availability, it would not be possible to go back to the 1990's to determine if there were a correlation between LF change and tariffs for LPUs. Therefore, it is not clear if the increasing LF from 2001 onwards is due exclusively to the decreasing Electrification rate, the increased pursuit of new energy intensive business within a favourable economic climate or the impact of the different TOU tariffs. The most likely scenario would suggest that a combination of these elements have contributed to the increasing LF since 2001.

9.4.2 Is an increased LF still required?

Higher load factors imply generation plant is online for longer; this implies smaller reserve margins. Smaller reserve margins imply less opportunity for maintenance. Less maintenance imply greater risk of plant failure; this implies higher prices due to RTP; this implies higher long run marginal cost, which further implies higher average prices.

Higher LF also implies generation with higher operational costs (like OCGT) is online for longer; this implies higher long run marginal costs; this implies higher average prices.

Higher LF that results in lower average prices require base load power stations that are online longer and peaking stations that are online for shorter periods; this implies lower long run marginal costs; this implies lower average prices.

When Calitz made the remark about higher load factors there was surplus capacity that even allowed certain power stations to be mothballed. Such levels of surplus capacity are not available anymore which means driving LF to unity is not ideal anymore.

To get back to the surplus levels that made Calitz's remark valid there would be a need for more base load power stations that are online for longer periods while peaking stations (OCGT) are used sparingly. Reserve capacity would be at higher levels that would make the loss of even multiple base load power stations manageable with no impact on customers. The capital costs of new base load power stations are higher which could make long run marginal costs higher which could ultimately drive average prices higher.

As detailed in section 9.5, an increased LF could be relevant if the ideal LF is higher than the present one. The ideal LF should be more representative of the generation mix with the most ideal maintenance strategy that allows for maximum operational availability and minimal risk of failure.

The downside of an increased LF includes environmental concerns. Eskom's 2009 Annual report states that the utility's overall environmental performance indicator due to emissions was negatively impacted due to (amongst others) the need for *power stations being run at higher load factors to meet demand for electricity*.

9.5 What should the LF be?

Calitz [1989] noted that he did not support the theory that there is an optimum load factor for different utilities. Instead, he argued that load factors have no upper limit and should be driven towards unity.

Eskom's 2009 Annual Report indicated that the utility should be *running generation plant at appropriate load factors, allowing for adequate maintenance and ensuring longer-term sustainable plant performance* [Eskom, 2009c].

LF should be reflective of the generation mix where base load stations are operated for the maximum possible time while expensive stations are run for the shortest possible time but still *ensuring high reliability of the network*. A load factor on its own is not very descriptive as too many variables are left unknown; an ideal load factor can only be described within the context of the ideal demand pattern. The ideal demand pattern then needs to be reflective of the generation mix which should ultimately lead to the 'perfect balance' between demand and supply.

Each type of generation technology, be it coal, nuclear, pump storage, gas, renewable, etc. has its advantages and disadvantages. They are often considered complementary to each other as specific technologies are rarely used in isolation for larger utilities that supply a diverse mix of customers.

The load profile could affect the choice of generation mix. As an extreme generation mix example, consider a generation mix that only includes coal power stations. Coal power stations are generally used as baseload stations and may be more suited for a relatively flat daily and seasonal load profile. However, it may not be ideal for a load profile with a relatively low daily load factor with sharp peaks (like the Electrification daily profile). A generation mix that can cater for short peak periods would more likely necessitate adequate peaking stations like OCGT.

Shifting toward one technology inevitably involves decision-makers making tradeoffs in their pursuit of advancing societal objectives¹¹. [Costello, 2007]

In SA, as Eskom is effectively government owned, and the regulator is a body that is appointed by government, the environment to cater for government's *societal objectives* is ideal. This could include keeping electricity prices affordable to the poor as part of the government's social responsibility. However, in lieu of the considerable tariff increases granted to Eskom from 2009/2010 onwards it now seems that tariff increases granted by the regulator during the 1990s that:

- did not appear to cater for future capacity investment
- and was declining in real terms

may have been inappropriate.

With a more diversified system, operators have more flexibility to cope with unexpected events. [Costello, 2007]

In South Africa this has particular significance as the OCGT, although planned as peaking stations, can be brought online relatively quickly to cater for short term capacity emergencies. This may not be the case for the existing coal or nuclear power stations. As OCGT's fuel costs are relatively high, care should be taken to avoid excessive operation outside Peak periods as this could contribute to higher long run marginal costs.

Costello [2007] further adds that:

... diversity can help to advance multi-dimensional societal objectives (e.g., low-cost generation, acceptable levels of pollutants, moderate price risk) at least cost. Optimal diversity allows the utility to be able to address different, and often conflicting, objectives that may vary over time (due to public pressure, regulatory requirements, political influence, etc.) at minimal additional cost.

¹¹ *The term "societal objectives" reflects the idea that generation planning has multiple objectives, relating to economic, environmental, and other dimensions. [Costello, 2007]*

Thus, driving the load factor to unity might be required if the daily and seasonal profile was practically flat and only baseload stations were available. Since neither scenario is applicable to South Africa, this goal is not valid anymore.

However, consideration should be given to the ideal generation mix. Generally, the future generation mix, and by implication, future load factor could be influenced by the following:

1. The existing generation mix.
2. The future load profile.
3. The impact of the tariffs on the load profile.
4. The impact of residential tariffs on the load profile.
5. The availability and affordability of fuel sources.
6. The increasing demand for environmentally friendly sources.
7. The wholesale electricity tariffs and the entry of independent power producers.

This study has shown a strong correlation between the load profile (weekly) of existing Electrification load and a peak during the evening Peak period for the Western Region. This study has suggested that any TOU tariff gains from reductions during the evening Peak period seems to have been nullified by the residential segment.

In lieu of the outstanding Electrification load that must still be connected as part of the government's social responsibility, the evening peak during the Peak period may become more prominent leading to a lower load factor profile. This would suggest a greater need for more peaking stations like OCGT. Peaking stations with high fuel/operating costs could lead to higher long run marginal costs and, ultimately, higher average costs.

If the practice of protecting the poor from tariff increases is continued indefinitely, the poor have no reason to change their consumption habits. The risk of eroding the subsidy base becomes more realistic, leading to even higher prices for all customers, and eventually, even the poor could experience the full impact of tariff increases.

The future generation mix and ideal load factor are topics that need to be investigated in much more depth but is considered outside the scope of this thesis.

10. Final Word

This chapter reviews the questions raised in Chapter One and assesses the validity of the hypothesis.

The questions that emanated from the hypothesis include:

8. What are the origins of TOU tariffs and what has the world learnt since its inception?
9. What was the goal of TOU tariffs in South Africa?
10. How have the results reflected in relation to its intended goals?
11. What level of effectiveness has been achieved with TOU tariffs in the Western Region?
12. If effective, can TOU tariffs be extended to more customers in South Africa? What are the barriers to further TOU tariffs in South Africa? How is South Africa different from the rest of the electricity tariff world? What is the South African requirement with respect to the demand profile? What key factors, including for example municipal policies and electrification, affect the shape of the national demand profile?
13. Can tariff options address the regional, and by implication, the national demand profile concerns?
14. Are TOU tariffs the 'be-all' of South Africa's requirements? What happens after TOU pricing? What other Pricing options are available?

10.1 What are the origins of TOU tariffs and what has the world learnt since its inception?

TOU tariffs have been in place for than 50 years across the globe. Many experiments have focussed on the response of the different types of customers' response to the different tariffs. It was clear that customers did respond and the level of response was determined by several factors other than price differentials of tariffs. Factors such as climate, longevity of TOU programme, level of appliance ownership, availability of alternative sources of energy, on-site generation, etc. all contribute to the response of customers. It was found that tariffs with enabling technologies that allows the technology to reduce load and relies less on a manual response from the customer has the best chance of a sustainable solution.

10.2 What was the goal of TOU tariffs in South Africa and how have the result reflected?

According to several publications by Calitz, the goals of TOU tariffs included shifting load from the peak times to the off-peak times characterised by lower fuel costs, conserving capacity (especially during peak times) and improving the system load factor.

It has been shown that the seasonal and time differentiated aspects of TOU tariffs have proven to be effective with some groups of LPUs. There is a strong correlation between the more expensive time differentiated Peak periods during the High Demand Season, and from a seasonal perspective the more expensive High Demand Season, and reduced load. In addition, there is a correlation between the less expensive Standard and Off-peak periods and increased load. Therefore, capacity conservation and load shifting appears to be reflected in the response of some LPUs.

The exceptions to this type of response include Agricultural LPUs that do not appear to be making significant changes in their demand profile, especially their seasonal demand profile. It is evident that their seasonal profile is much more dependent on the seasonality of their crops rather than the effect of TOU tariffs.

The other exceptions are Rural Municipalities and City of Cape Town. It was found that LPUs with significant residential components are more likely to peak during the High Demand Season, and especially during the Peak periods of the High Demand Season. However, the City of Cape Town is a good example of a municipality that can manage their load despite their significant residential component. The City of Cape Town is appearing to implement effective load management so that the demand during the evening Peak period is only marginally higher than the demand during the morning Peak period.

During the 1990s the system load factor appeared to be declining which coincided with the widely implemented Electrification period. It was found that the residential area that was chosen as a typical Electrification area highlighted a load profile that was characterised by the lowest daily load factor in relation to the other sampled residential areas. This justifies one of Calitz's concerns that Electrification could lead to a declining load factor due to the introduction of load with relatively low load factor.

The system load factor on a national level has been increasing since 2002 with a decline in 2009. The increasing load factor can most likely be attributed to the addition of energy intensive industry that was pursued by Eskom due to the perceived excess generation capacity. In addition, there was a considerable decline in the rate of Electrification from the high levels during the 1990s while older Electrification areas were starting to increase their load factor as their economic situation improved. The reduction in 2009 can most likely be attributed to the extensive load shedding that took place during 2008.

10.3 If effective, can TOU tariffs be extended to more customers in South Africa?

It has been shown that Eskom's typical residential areas have profiles that peak during the evening Peak periods and during the High Demand Season. These characteristics are repeated in LPUs with significant residential components (with the City of Cape Town being the exception from a daily perspective). If TOU tariffs were so effective for the LPUs in the Western Region, then it would be expected that they could elicit a similar response from the residential customer as well.

From a load factor perspective, it was found that area chosen as a sample for Middle Income residential customers had the highest load factor for the month of July 2008 amongst the residential groups. Due to the customers in this group having a generally higher ADMD, they are bound to make a greater contribution to the peak demand during the Peak periods; thus they could be considered ideal candidates for TOU tariffs. There seems to be strong political support for TOU tariffs for these customers as detailed by various government legislative documents with published target dates for implementation [DME, 2008a; DME, 2008b].

In contrast, Electrification customers have the lowest load factor for the same period while electricity is used mostly for cooking, lighting and boiling water in a kettle. Considering South Africa's political history that resulted in severe inequality, the government noted that providing electricity to the poor (mostly black people) is deemed a social responsibility and a poverty alleviation tool. As these customers benefit from Free Basic Electricity, the government seems to rather support Energy

Efficiency and an Inclining Block rate tariff (as opposed to a TOU tariff) for these customers as per government legislation.

The first Inclining Block Rate tariff has already been announced for implementation by Eskom in 2010 during Nersa's tariff approval statement in 2010 [Nersa, 2010]. However, it is applicable across the residential spectrum and not only for poorer households. It remains to be seen how the Inclining Block rate will evolve into a TOU tariff for Middle Income customers as proposed in earlier pricing documents [DME, 2008a; DME, 2008b].

The country's needs could be considered two-fold. Firstly, due to load shedding throughout the day, Energy Efficiency, and maybe more importantly, Energy Conservation is considered as an important tool to address the short term capacity problems. Secondly, the benefits of TOU tariffs like peak clipping, valley filling and improved load factor are considered more medium to long term goals. Adding new generation capacity to keep track of demand is very capital intensive. If capacity conservation is not addressed continuously, there will be earlier needs for new generation capacity which tends to put upward pressure on average prices.

As stated in Chapter Eight, municipal tariffs are often not formally approved by Nersa. The City of Cape Town has introduced an Inclining Block Rate tariff to its residential customers; however, it is only available to consumers who use less than 450kWh per month. Attempts to address the challenges that may be highlighted by the national demand pattern via tariffs would achieve more if all retail customers – Eskom and municipal - adhere to tariffs that are based on the same set of rules and requirements.

10.4 Are TOU tariffs the 'be-all and end-all' of South Africa's requirements? What other Pricing options are available?

In countries where TOU pricing is well established, like many first world countries, this tariff is seen as the most basic of pricing options. The tariff caters for normal conditions with no allowance made for short term supply challenges that the utility may face. In order to cater for most short term conditions, Real Time Pricing is being hailed as the solution where all risks that the utility faces are shared with the customer. However, this is more applicable where the generation, transmission and

distribution limbs do not form part of the same company and there is competition on the generation front.

Considered somewhat of a compromise between RTP and TOU, is TOU + CPP (Critical Peak Pricing). A South African government Gazette No. 31741 [DME, 2008a] appears to support TOU + CPP that caters for *an approved super peak rate to reflect the short term costs* [DME, 2008a].

Tariffs were not intended to be a static entity but something that would change in reaction to customers' response while customers would continuously be adjusting their consumption patterns in response to tariffs. Ultimately, the tariff customer relationship would always be moving towards the perfect balance between pricing signals (that are reflective of the generation mix) and customer response.

10.5 Assessing the hypothesis

The hypothesis read:

Time of Use tariffs have been effective in the Western Region.

The assessment of TOU tariffs in the Western Region has shown that:

- From Chapters Six it has been shown that LPUs without significant residential components have a preference for the Low Demand Season. This preference is indicated by the correlation between increased demand and energy consumption, and lesser costs of the Low Demand season. The exception is the Agricultural group whose seasonal response is dictated by the seasonality of their crops rather than a response to a tariff.
- The samples of the different groups of Eskom's residential customers in the Western Region indicate that demand and energy clearly peaks during the High Demand season for the residential sector.
- LPUs with a significant residential component (Rural Municipalities and the City of Cape Town) do not appear to be responding to the seasonal component of TOU tariffs. Demand still peaks during the more expensive High Demand season for these LPUs.
- From Chapter Seven, it has been shown that LPUs without significant residential components have the flexibility to shift load from Peak periods to Standard and Off-peak periods. This is indicated by load reduction noticed

prior to the advent of the Peak period and a load increase after the Peak period. This is further indicated by a strong correlation between reduced average half-hourly indices for the Standard and Off-peak periods and lesser costs of those periods for the month of July 2008.

- It has been shown the samples of the different groups of Eskom's residential customers clearly peak during the Peak periods, and especially the evening Peak period. As most residential customers were on a flat tariff, electricity demand patterns are rather determined by social patterns in the specific areas.
- It has been shown that LPUs with significant residential components (Rural Municipalities) do not appear to be responding to the higher costs of the Peak periods.
- It has been shown that the residential sector appears to have a considerable influence over the seasonal and daily response of LPUs with a significant residential component. The City of Cape Town is the exception, as they appear to have an effective load management system in place in conjunction with self-generation to ensure a relatively flat daily profile.

From Chapter Nine, Calitz's goals included load shifting, capacity conservation and improved load factor.

- It has been shown that LPUs without significant residential components appear to have a preference for the cheaper Standard and Off-peak periods. This implies that some level of load shifting has taken place.
- Load shifting inherently implies capacity conservation during Peak periods which is when the country has its greatest challenge.
- From Chapter Nine, it was shown that on a national level the morning peak had grown at a slower rate than the evening peak. The morning peak could have been influenced by two factors, viz. the impact of the higher costs of the Peak period that deterred Peak period usage, while the Electrification residential sector did not display a considerable increase in relation to the rest of the day.
- The evening peak does not appear to have been influenced significantly by TOU tariffs. LPUs without residential components could have reduced load during the evening Peak period; however, the residential sector's demand pattern showed a clear tendency to peak during the evening Peak period. Any

reduction by the LPUs during the evening Peak period may have been surpassed by the increased demand from the residential sector.

- Nationally, it has been shown that the load factor was decreasing during the 1990's but is increasing during the subsequent decade. The decrease correlates with increased Electrification connections; the increase correlates with decreased Electrification connections, increased industrial activity and a favourable economic environment. In order to say which had the most significant impact on the increasing load factor would require much more in-depth economic analysis which is beyond the scope of this study.

Therefore, with the exception of Agricultural LPUs, the hypothesis has been proven to be true, both seasonally and daily, for LPUs without significant residential components. This is not the case for LPUs that do have significant residential components.

10.6 Novel Aspects

The tools that have been developed in this thesis can be applied in the other regions of Eskom Distribution with some minor adjustments as the database is very similar. It is envisaged that the tool can be applied to determine a regional customer profile to better understand the customer base in the respective regions. Should the Regional Electricity Distributors (REDs) become a reality where all retail customers would be part of one of the REDs, each RED would need to understand their customer base to determine their own specific tariff requirements based on their specific conditions. This tool could then play a valuable role in determining the individual REDs' tariffs.

Appendix

Year	Integrated System Load Factor	Generation Load Factor
1981	78%	62%
1982	75%	59%
1983	77%	56%
1984	75%	58%
1985	76%	58%
1986	77%	56%
1987	74%	54%
1988	76%	52%
1989	74%	51%
1990	75%	51%
1991	75%	50%
1992	74%	47%
1993	75%	47%
1994	73%	51%
1995	74%	52%
1996	72%	56%
1997	74%	58%
1998	75%	55%
1999	76%	55%
2000	75%	55%
2001	73%	54%
2002	74%	57%
2003	77%	60%
2004	77%	69%
2005	78%	69%
2006	80%	70%
2007	83%	72%
2008	85%	72%
2009	79%	67%

**Table 1 National Integrated System Load Factor and Generation Load Factor
[Eskom, 1987, 1990, 1993, 1996, 1999, 2002, 2006, 2010a]**

MINIFLEX	2001	2002	2002(2)	2003	2004	2005-6	2006-7	2007-8	2008-9
Network Access Charge (Rands)						5.62	5.91	6.26	7.15
Peak HDS (cents)	43.16	45.84	45.47	50.56	51.82	50.81	53.4	56.55	64.6
Standard HDS (cents)	13.03	13.84	14.3	15.79	16.18	14.71	15.46	16.37	18.7
Off-peak HDS (cents)	7.47	7.93	9.16	10.07	10.32	7.07	7.43	7.87	9
Peak LDS (cents)	31.89	33.87	15.08	16.67	17.09	15.67	16.47	17.44	20
Standard LDS (cents)	11.69	12.41	10.54	11.6	11.89	10.38	10.91	11.55	13.2
Off-peak LDS (cents)	6.72	7.14	8.37	9.18	9.41	6.13	6.44	6.82	7.8

Table 2 Miniflex Annual tariff detail [Eskom, 2001, 2002a, 2002b, 2003, 2004, 2005, 2006a, 2007b, 2008b, 2008c, 2009d]

MEGAFLEX	2001	2002	2002(2)	2003	2004	2005-6	2006-7	2007-8	2008-9
Network Access Charge (Rands)						5.62	5.91	6.26	7.15
Demand Charge HDS (Rands)	12.87	16.67	8.17	10.13	10.33	6.37	6.69	7.08	8.1
Demand Charge LDS (Rands)	11.59	12.31	8.17	10.13	10.33	6.37	6.69	7.08	8.1
Peak HDS (cents)	31.05	32.98	45.49	49.43	50.44	49.69	52.22	55.3	63.2
Standard HDS (cents)	13.03	13.84	13.11	14.25	14.56	13.14	13.81	14.62	16.7
Off-peak HDS (cents)	7.47	7.93	7.76	8.45	8.63	7.15	7.51	7.95	9.1
Peak LDS (cents)	20.9	22.2	13.92	15.14	15.45	14.1	14.82	15.69	18
Standard LDS (cents)	11.69	12.41	9.21	10.02	10.23	8.75	9.2	9.74	11.2
Off-peak LDS (cents)	6.72	7.14	6.94	7.55	7.72	6.2	6.52	6.9	7.9

Table 3 Megaflex Annual tariff detail [Eskom, 2001, 2002a, 2002b, 2003, 2004, 2005, 2006a, 2007b, 2008b, 2008c, 2009d]

RURAFLEX	2001	2002	2002(2)	2003	2004	2005-6	2006-7	2007-8	2008-9
Network Access Charge (Rands)			1.81	2.86	3.04	3.27	3.44	3.64	4.16
Peak HDS (cents)	51.57	54.77	62.69	71.11	75.8	82.13	86.32	91.41	104
Standard HDS (cents)	15.54	16.5	16.41	18.49	19.71	21.24	22.32	23.64	27
Off-peak HDS (cents)	9.04	9.6	8.78	9.85	10.5	11.28	11.86	12.56	14.4
Peak LDS (cents)	36.94	39.23	17.54	19.76	21.06	22.75	23.91	25.32	29
Standard LDS (cents)	13.94	14.8	10.8	12.1	12.89	13.88	14.59	15.45	17.7
Off-peak LDS (cents)	8.09	8.59	7.58	8.47	9.03	9.66	10.15	10.75	12.3

Table 4 Ruraflex Annual tariff detail¹² [Eskom, 2001, 2002a, 2002b, 2003, 2004, 2005, 2006a, 2007b, 2008b, 2008c, 2009d]

NIGHTSAVE Urban	2001	2002	2002(2)	2003	2004	2005-6	2006-7	2007-8	2008-9
Energy Demand Charge HD (Rands)						29.09	30.57	32.37	37
Energy Demand Charge LD (Rands)						4.12	4.33	4.59	5.25
Network Access Charge (Rands)						5.62	5.91	6.26	7.15
Demand Charge HD (Rands)	40.23	42.72	26.15	41.72	48.31	6.37	6.69	7.08	8.1
kW Charge HD (Rands)	46.17	79.03	30.77	49.1					
Demand Charge LD (Rands)			10.66	14.17	14.39				
kw Charge LD (Rands)			12.54	16.68					
Energy HD (cents)	7.26	7.71	12.42	12.45	12.65	10.13	10.65	11.28	12.9
Energy LD (cents)	7.26	7.71	9.16	9.35	9.5	7.2	7.57	8.02	9.2

Table 5 Nightsave Urban Annual tariff detail [Eskom, 2001, 2002a, 2002b, 2003, 2004, 2005, 2006a, 2007b, 2008b, 2008c, 2009d]

¹² 2 sets of tariffs were released for 2002, each for 6 months. The 2005 tariffs were from 01 January 2005 to 31 March 2006. Eskom had attained permission to change its financial year-end from 31 December to 31 March.

Table 2 — Classification of domestic consumers — Typical design load parameters for domestic consumers¹⁾

1	2	3	Load parameters – 7 years ^{c,d,e,f}				Load parameters – 15 years ^{c,d,e,f}							
			4	5	6	7	8	9	10	11	12	13	14	15
Consumer class	Current type AMPS ^a and LSM ^a class	Income range ^b (gross R/month)	a	b	c	ADMD kVA	μ A	δ A	a	b	c	ADMD kVA	μ A	δ A
			Rural settlement	LSM 1 (low end)	0 to 600	0,30	2,98	20	0,42	1,83	2,78	0,35	2,88	20
Rural village	LSM 1 and 2	400 to 900	0,43	2,52	20	0,67	2,91	3,55	0,48	2,13	20	0,84	3,65	4,07
Informal settlement	LSM 3 and 4	800 to 1 500	0,77	9,88	60	1,00	4,35	4,56	0,91	8,80	60	1,30	5,56	5,36
Township area	LSM 5 and 6	1 500 to 3 000	1,05	7,81	60	1,64	7,13	6,18	1,22	5,86	60	2,37	10,30	7,96
Urban residential I	LSM 7	3 000 to 5 500	1,23	5,56	60	2,50	10,87	8,28	1,25	3,55	60	3,59	15,61	10,93
Urban residential II	LSM 7 and 8	5 500 to 8 500	1,45	6,07	80	3,54	15,39	10,81	1,42	4,10	80	4,72	20,52	13,68
Urban township complex	LSM 8	8 500 to 12 000	1,45	5,75	80	3,70	16,09	11,20	1,42	4,13	80	4,70	20,43	13,63
Urban multi-storey/estate [†]	LSM 8 (high end)	12 000 to 24 000	1,43	4,41	80	4,50	19,57	13,15	1,37	3,39	80	5,30	23,04	15,09

^a Living standards measure (LSM) as quoted in the All Media and Product Survey (AMPS) conducted annually by the South African Advertising Research Foundation.

^b Average household income ranges shown for comparative purposes are in 2005 Rands. Any income data collected at a later date should be deflated by the CPI to allow a direct comparison.

^c If the target community matches the description, but the chosen value of c is different, new a and b values can be calculated for the chosen value of c , using the formula given in B.4.3.

^d Parameters have been normalized to the climate in the interior of South Africa where the winters are generally cold and with low rainfall. In regions where the winter is cold and wet (e.g. Cape Peninsula), the ADMD is about 12 % higher than that given. In climates similar to that of the Durban coastal region, the ADMD is about 12 % lower than that given.

^e Except as indicated in f below, the parameters have been derived from carefully monitored case studies around the country, and reflect best knowledge at the time of publication of actual consumer demand over time. The actual load parameters used depend upon the strategy of the planner with regard to phasing of capital expenditure.

^f Parameters for this consumer class have been extrapolated from existing data, since no sample load data have yet been collected from such consumers. Loads significantly higher than the ADMD shown in LSM 8 (high end) can be expected in the case of specific high-consumption developments. In such cases, estimated load data should be obtained from the relevant local authority or licensee.

Table 6 NRS 034 LSM group detail [SANS, 2007]

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