Cost of Providing Ancillary Services from Power Plants

Reactive Supply and Voltage Control

TR-107270-V3

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REPORT SUMMARY

This report provides a methodology for determining the variable costs of generating and supplying reactive power to a transmission system, via the generator step-up transformer, for system voltage control. The report examines the costs of additional energy losses, maintenance, repair, and plant aging associated with the generation of reactive power.

Background

Generating plants have historically been rated to provide reactive power for voltage control although the cost of this service has rarely been analyzed. However, with the unbundling of generation and system assets and the emergence of more transparent electricity markets, contractual provision must be made for reactive power. This raises the question of how much it costs to provide this service.

Objectives

To provide a methodology for calculating the cost of energy losses and the likely costs associated with repair, maintenance, and plant aging associated with the generation of reactive power.

Approach

The project team used known equipment parameters to calculate the electrical losses associated with reactive power. They employed a flexible approach that incorporates reasonable assumptions to compensate for unavailable data on the variability of different loss components, magnetic saturation in the generator, and the change in winding resistance with temperature. They estimated maintenance and repair costs by identifying the underlying factors such as vibration, temperature, or stress that can cause damage. They calculated the costs associated with reactive power by scaling the historical incidence of costs with an appropriate factor that accounts for the contribution reactive power generation makes to the underlying damage mechanism.

Results

This report presents a methodology for calculating the cost of energy losses in the generator and transformer associated with reactive power, as well as related maintenance, repair, and plant aging costs, Individual case studies using the methodology are not included; but the methodology shows that the costs, while small in relation to the cost of real power, are still significant. Because loses are proportional to I^2R and increases in losses also increases winding temperature and hence resistance, the effect of generating reactive power is to increase losses in a non-linear manner. The cost of each MVAr of reactive power is relatively low when a plant is operating near to unity power factor but steadily increases as reactive power increases. The same non-linearity occurs with the maintenance, repair, and aging costs since the main underlying damage mechanisms that relate to reactive power are normally associated with a current squared term. The methodology requires the analysis of each individual cost component at both the unity power factor condition and the required load condition: the difference between these values is the cost required to generate reactive power. A spreadsheet is required to calculate costs over a range of load condition.

Volume 1 of this report, already in print, supplies background information about ancillary services and discusses EPRI's future plants for developing additional tools to help owners of power plants compete in a deregulated power supply industry. Volume 2 provides a detailed description of a methodology for calculating the variable costs of providing Regulation and Frequency Response. Volume 4, forthcoming, will give additional detail on the methodology for calculating the variable costs of providing Operating Reserve-Spinning.

EPRI Perspective

EPRI's plan for its ancillary services projects involves testing methodologies developed for calculating the variable and fixed cost of providing ancillary services using data from several different units. Then, based on the results of these case studies, EPRI expects to identify a range of costs for ancillary services produced by all kinds of power plants. Utilities interested in using the methodologies are urged to contact Jan Stein at EPRI at (415) 855-2390 to participate in the on-going research.

TR-107270-V3 (U.S. Units); TR-107270-V3SI (System of International Units)

Interest Categories

Fossil assets management
Power system operations and control
Bulk power markets and transmission

Key Words

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EXECUTIVE SUMMARY

The need to generate reactive power is just as important as is the generation of real power since power system loads and transmission equipment, such as induction motor drives, overhead lines, cables and transformers, impose both a real and reactive load on the connected generators. One difference however is the dominant effect reactive power flows have on the voltage profile of the network and it is this feature which makes the localized control of VAr generation so important.

Because reactive power does not imply a net transmission of energy from the power station to the network, it does not mean that it is free to produce. The electrical current generated is higher and losses, primarily in the generator, transformer and transmission system are greater. The increased currents, particularly in the generator rotor at lagging power factors, cause the windings to operate at higher temperatures, imposing greater thermally induced mechanical stresses, relative movement and levels of vibration. Such factors are responsible for many of the problems requiring routine maintenance and repair and are often a prime cause of equipment ageing.

This report provides a logical way of calculating the variable costs of generating VArs due to equipment losses, maintenance, repair and ageing: it examines the costs from the viewpoint of the generating station and does not seek to evaluate cost effects in the transmission and distribution system. The methodology uses basic equipment data to determine the cost of the additional losses and historical operating and cost data to analyze the cost of repair, maintenance and equipment ageing. In any analysis of this sort some engineering judgments and estimates are required by the user. The methodology discusses the issues and provides the framework within which these judgments can be made and the costs calculated and justified on a logical basis of cause and causation. Costs associated with “lost” generation during normal operation, maintenance and repair are also covered but not in relation to plant operating decisions and risks imposed by a regulatory framework. The methodology presented is suitable for being translated into a software spreadsheet application.

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INTRODUCTION

This report aims to provide a methodology for calculating the variable cost to a power generating station of generating reactive power, VArs, required by the loads connected to the power system and the transmission equipment itself. The costs calculated do not include any fixed capital cost component; although it is clear that such a component is quite real and not insubstantial since the ratings of generators and transformers are typically designed for power factors in the range 0.9 to 0.8 and this increases equipment size and cost significantly. What is of interest in this report is the variable cost: that is the additional cost of generating VArs as opposed to generating at unity power factor. This leads to two fundamental definitions adopted in the report:

i) VAr generation is defined at the output terminals of the high voltage step-up transformer (assumed to be the boundary between the generating station and the transmission network). This will not be quite the same as the VAr output of the generator due to the VArs absorbed by the step-up transformer itself. In the event that the boundary between generation and system is at the generator terminals, the methodology can still be used by ignoring the transformer cost components and reactive impedance.

ii) Variable costs of VAr are defined as the costs of generating a given real and reactive power into the system at the particular system voltage required, less the cost of generating the same real power at unity power factor at the same system voltage.

The terms of reference for this report are to develop a methodology to calculate the variable cost of generating VAr due to increased plant energy losses and maintenance, repair and plant ageing costs associated with VAr. The VAr related cost of "lost" generation from plant outages, or from operation at reduced power to accommodate an increase of VAr generation, is covered briefly but the report does not attempt to examine other costs which can legitimately be related to VArs, associated with plant risk management, the holding of strategic spares and costs associated with operating under a particular regulatory framework.

It is intended that the methodology can be used, not only to calculate the variable costs of generating VArs at a particular level of power, but also to calculate the integrated costs of generating VArs assuming a particular pattern of real and reactive power over time. It is envisaged that the methodology will require the development of a software spreadsheet since equations associated with defining generator operating conditions and the effect of saturation on generator excitation make calculations laborious. To reflect this, the equations contained in this report are in a spreadsheet style and, wherever possible, the order of calculation follows that which must be used in the development of a spreadsheet.

1.1 VAr Related Losses

The most obvious cause of the variable costs of generating VArs is due to the increased energy losses mainly in the generator and transformer. When the power factor drops below unity, additional reactive current is conducted, increasing the total current and associated I^2R and stray (eddy current) losses in all windings subjected to alternating current. The exception to this is the generator rotor excitation losses. At leading power factor operation, generator rotor excitation losses will tend to reduce causing the curve of total losses, as a function of power factor, to be asymmetric about the unity power factor condition. At lagging power factors rotor excitation can require a very significant increase in excitation requirements with these losses increasing rapidly. Testing plant to determine the variation in losses as power factor is altered, is not likely to lead to accurate results since the VAr related losses are only a modest fraction of the (typically 2%) loss component attributed to the generator, transformer and exciter at full load. The problem of measuring and time averaging turbine steam flows and pressures to a fraction of one per-cent makes this approach inaccurate and a calculation technique along the lines given in international standards[1] to calculate generator efficiency, based on the summation of losses, is preferred.

Once the additional VAr related losses have been calculated the issue of costing these losses needs addressing. Logically there are two valid approaches. If a generator is at part load then clearly the output is being matched to system requirements and the fact that extra losses occur is simply made up by burning more fuel to obtain the desired output. In this case the cost of the VAr related losses is calculated from a knowledge of the cost of the extra fuel required. If, however, the output requested is the full load rating of the unit then it can be argued that if the extra losses did not occur, the extra power could be sold at the full power purchase price and it is this monetary difference which can be thought of as the cost of the losses. In reality this argument is only valid if the generating unit can be treated in isolation since, if this extra power was available to the system, then somewhere another generating unit would generate less, get a reduced income and burn less fuel; the net difference again being a reduction in the overall fuel cost. (In this situation there would be some logic in using the fuel cost and thermodynamic efficiency of the marginal plant called on to match the system load demand.) However, for the purposes of this report, the definition given above, item ii), can be extended to define the cost of losses as:

iii) The cost of VAr related energy losses is assumed to be related to the cost of fuel required to generate the additional losses and not the loss of income should the losses not occur and the power be available to be sold.

However, the methodology can easily be altered to take the alternative (loss of income or the marginal cost of losses) approach if this is thought more appropriate by the user.

1.2 Maintenance and Repair Costs

While it is possible to examine typical costs of routine maintenance and relate this to levels of power (MW) and reactive power (VAr) generation, even the costs of planned maintenance can vary depending on the amount of remedial work required. For unplanned repair outages the situation is essentially a random and infrequent event and such features make it impossible to predict actual costs with much certainty. Basing present and future maintenance and repair costs on historical records (suitably indexed for inflation) is therefore preferred so that the basis of the cost figures used are well founded. In this way analysis of historical records of maintenance and repair costs, linked to power and VAr generation and averaged over as much time and similar plant as possible, is considered to be the best way of reducing the effects of any one single incident or maintenance outage.

Once historical data is available, the problem then comes in trying to determine what part can reasonably be attributed to VAr production. A general discussion of damage and ageing mechanisms in generators is given in reference.[2] The method adopted in this report relies on being able to attribute each maintenance or repair cost to one or more damaging effects, such as gas into coolant leaks in the generator endwinding caused by excessive endwinding vibration. Once the underlying mechanism is identified, the effect of generating VAr can be estimated based on the effect VAr is likely to have on the damage mechanism. For instance, in the case of endwinding vibration induced problems, the vibration is approximately proportional to I^2 and, since I^2 is proportional to $MW^2 + MVAr^2$, the costs attributed to VAr are given by the time averaged fraction $MVAr^2 / (MW^2 + MVAr^2)$. As with any method of this type, a degree of engineering judgment must be made and it is the intention that the method allows flexibility to build in specific plant knowledge.

The difference between maintenance, repair and the effects of plant ageing need to be defined for the purposes of this report:

iv) Maintenance can be defined as known operations required to optimize the cost of operating the plant reliably, the frequency of which may be related to the mechanism producing the problem.

v) Repairs can be defined as non-routine maintenance. Replacement of minor components or replacement of part of a major component (such as some stator winding bars within a winding) would constitute a repair.

vi) The effects and costs of plant ageing can be defined as occurring when a major component is replaced as a whole because the reliability of the component, if repaired locally, is not sufficiently high.

1.3 Plant Ageing

The distinction between plant ageing and repair is difficult but has been defined above, in v) and vi), as when a decision is made to completely replace a major component, such as a generator rotor, or to rewind the rotor completely. It is considered that, while the event might have been due to a single localized failure, such a decision would indicate that the reliability of the component is uncertain due to the accumulated effects of plant ageing. Clearly individual decisions may make this distinction difficult but in any event the effect should not be significant on costing VArs since the historical costs are factored into one or other categories. The costs associated with plant ageing related to VAr generation are defined as:

vii) Plant ageing costs are related to the difference in the net present value of component replacement costs expected for a particular level of VAr generation and the expected annualized cost of component replacement if operated at unity power factor.

This component of cost is likely to be the most uncertain and again only experience can be a guide as to the most likely causes of plant ageing and the most probable life limiting problem.

1.4 Outline Methodology for Costing VArs

The overall concept of the methodology for calculating the variable cost of VArs is shown in Figure 1-1. The simplified example given below illustrates the process although it is limited to only two out of the many cost components which need to be considered.

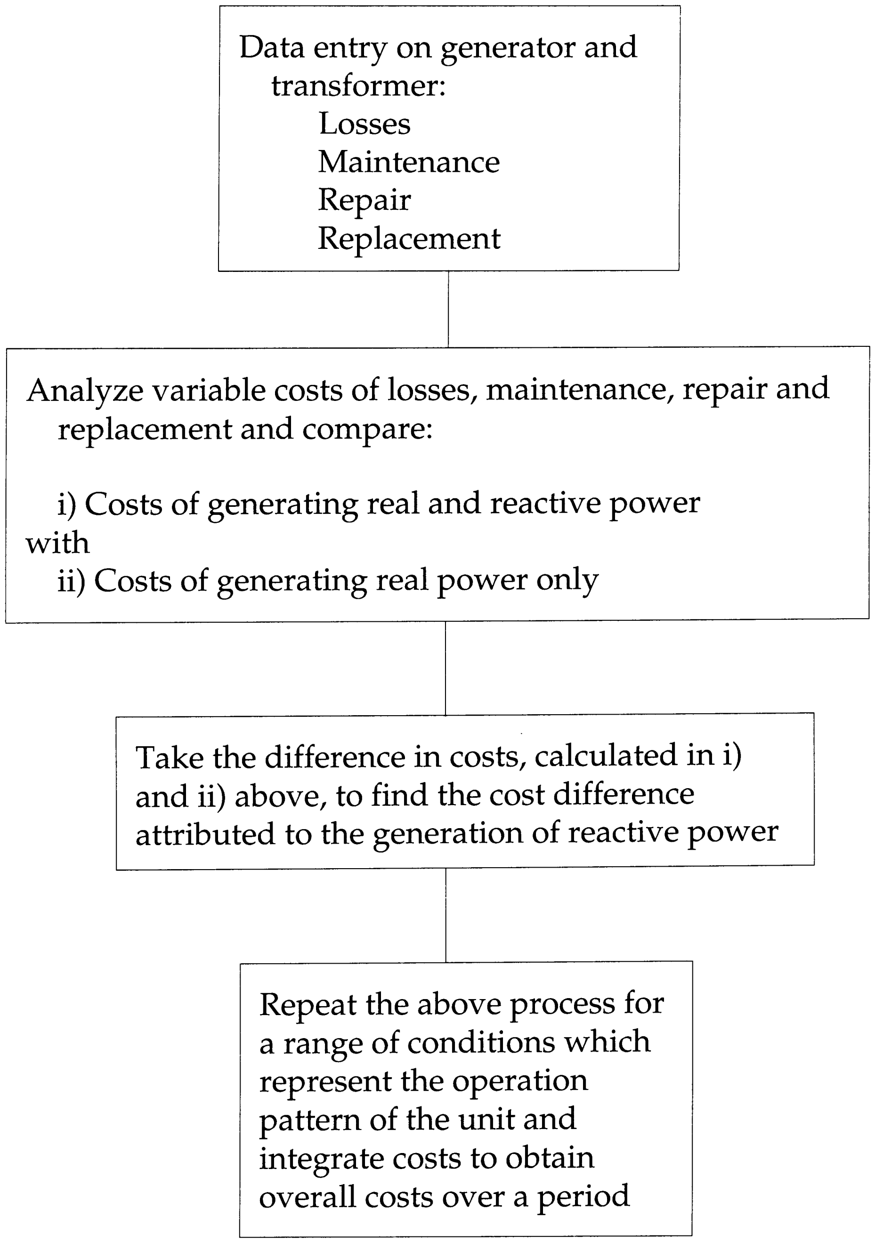

Figure 1-1
Flow diagram for the VAr costing methodolgy.

Example:

Consider a generator rated at 300MW, 22kV with a stator winding resistance of 0.0025 Ohms/phase. The generator normally operates continuously at full load 0.85pf. The unit has an overall thermal efficiency of 36% and the cost of fuel is 0.2 cents/MJ. The generator has a history of requiring maintenance/repair associated with the stator endwindings due to vibration loosening the bracing arrangement. This has led to additional costs averaged over each year of operation, of $30,000/year.

Taking this limited information, the variable cost of generating VAr associated only with the stator winding losses and the maintenance/repair of the stator endwindings can be determined as:

Stator winding losses at normal load (0.85pf) $= 3 \,.\, 0.0025 \,.[300\times10^6/(0.85 \,.\, \sqrt{3} \,.\, 22000)]^2$
$= 643\text{kW}$

Stator winding losses at unity power factor $= 3 \,.\, 0.0025 \,.[300\times10^6/(\sqrt{3} \,.\, 22000)]^2$
$= 465\text{kW}$

Extra losses in stator due to VAr generation $= 643 - 465\text{ kW} = 178\text{kW}$

Additional fuel energy required per MVAr.hr $= 178\times10^3\text{W} \,.\, 3.15\times10^7$ seconds/year .(100/36%)
$= 1.56\times10^7$ MJ/year

Fuel cost of VAr related stator resistance losses $= 1.56\times10^7$ MJ/year. 0.2 cents/MJ/100
= $31.2k/year

Maintenance and repair of the stator end-windings is related to electromagnetic vibration which is excited largely as a result of stator winding current interacting with its own self generated leakage field: vibration is therefore proportional to current squared. Generation of VAr therefore increases the rate of deterioration and the incidence of repair. Since the damage mechanism has been identified as I^2, the cost of each Amp^2hour is first calculated for the period of known operation which has resulted in the known damage and repair costs. These costs are then applied to the unity power factor condition to calculate the costs of repair which would be expected under these less onerous conditions. The costs of VArs is then related to the difference in these two costs. The calculation is as follows:

Integrated value of I^2 over the known cost period (1 year) $= [300\times10^6/(0.85 \,.\, \sqrt{3} \,.\, 22000)]^2 \,.$ 8760hrs
$= 7.5\times10^{11}\ A^2$hrs/year

Cost of each A^2hr related endwinding repairs = $30k/year/$7.5\times10^{11} A^2$hr/year
$= 4\times10^{-8}\ \$/A^2\text{hr}$

Integrated value of I^2 for unity power factor over year $= [300\times10^6/(\sqrt{3} \,.\, 22000)]^2 \,.$ 8760hrs
$= 5.4\times10^{11}\ A^2$hrs/year

Additional A^2hr required to generate VAr $= (7.5 - 5.4)\times10^{11}\ A^2$hrs
$= 2.1\times10^{11}\ A^2$hrs/year

Cost of VAr related component of endwinding repairs $= 2.1\times10^{11}\ A^2\text{hrs/year} \,.\, 4\times10^{-8}\ \$/A^2\text{hr}$
= $8.4k/year

In practice the methodology is complicated by the need to cater for different levels of available data, the requirement to relate unity power factor operation back to output from the transformer terminals, the way in which conductor temperature is taken into account when calculating losses and the need to analyze both past and future production schedules. These difficulties point to the need to use an automated calculation technique, possibly a spreadsheet. Such a method is essential if the costs are to be numerically averaged over a whole range of load points which represent a prolonged period of generation. Assuming the methodology is incorporated into a spreadsheet, the work to calculate costs for a particular unit reduces to that needed to collect, review, pre-condition and enter the relevant data. Most difficulty is likely to be encountered in extracting maintenance and repair costs from records and in deciding the most likely cause of the underlying damage mechanism.

1.5 Assumptions

The following major assumptions are made in the analysis:

1. Capital costs are excluded from the methodology; only the variable costs are examined.

2. Costs associated with plant risk management, the holding of strategic spares, and any statutory or other drivers that dictate the timing or content of maintenance and repair work, have been excluded from the terms of reference and the costing methodology.

3. Costs of repair and maintenance are assumed to be linearly related to the present or future size of any underlying dominant damage mechanism. Any natural effect of costs to escalate towards the end of plant life is ignored but the effect that operation has on shortening plant life is taken into account.

4. Winding temperature rises are assumed to be proportional to the resistive losses dissipated in the winding.

5. All windings are assumed to be copper (the resistance temperature coefficient appropriate to copper is built into the equations.

6. The auxiliary power requirements, supplied from the generator LV busbar, constitute a lagging load which does not vary with any normally small changes in busbar voltage.

2

DATA REQUIREMENTS

The methodology developed to calculate the variable cost of VArs attempts to make as accurate analysis as is practically possible. To do this a fair degree of detail is required both of the plant, historical maintenance, repair and replacement records together with the operating history. It is acknowledged that the technical plant data may not be available in all cases and, while the result will only be as good as the data available, there is usually an assumption or approximation which can be made which minimizes the likely error.

2.1 Essential Plant Data

Although guidance will be given on reasonable assumptions and approximations which can be made, in the absence of data there is a core amount of data which is essential if the methodology can be made to work. This is as follows:

a) Rating-plate data for the generator

Rated load ($P_{gen-rat}$)
Rated line voltage ($V_{gen-rat}$)
Rated power factor ($PF_{gen-rat}$)
Full load efficiency ($\eta_{gen-rat}$)
Method of cooling (rotor and stator, direct or indirect, Air, H_2, or H_2O)
Temperature rating utilized (usually rated to class B temperatures)

Note: In the past, steam-turbine driven generator nameplates carried a *capability MVA* at maximum hydrogen pressure and a *rated MVA* at one atmosphere lower pressure. Per unit parameter values, including R1, were given on the *rated MVA* base. For many years now, generator nameplates have only identified *rated output at maximum* hydrogen pressure so that confusion is avoided. Clearly the information required by this methodology needs to be consistent with all the other data items which are defined at the rated condition; the actual choice of rating is not important.

b) Rotor excitation at rated voltage, open-circuit (I_{f-oc})

c) Generator d-axis synchronous reactance (Xd_{pu})

d-axis sub-transient reactance ($Xd_{pu}^{\prime}$)

q-axis reactance (salient pole m/cs only) (Xq_{pu})

d) Rotor excitation at rated load
Rated field current ($I_{f\text{-}rat}$)

e) Rating-plate data for transformer
Rated MVA ($MVA_{t\text{-}rat}$)
Rated LV line voltage ($V_{t\text{-}LV\text{-}rat}$)
Rated HV line voltage ($V_{t\text{-}HV\text{-}rat}$)
Reactance (nominal) ($X_{t\text{-}nom\text{-}pu}$)
Full load efficiency ($\eta_{t\text{-}rat}$)

Note: transformer nameplates may carry a variety of *ratings* such as OA, FA, FOA in addition to the 130 deg.F and 150 deg. F rise values. The transformer reactance is most commonly given on the self cooling rating, OA. Confusion can occur. Clearly the data required at a nominal rating must be consistent and should reflect its normal mode of operation.

f) Typical routine maintenance costs (present value), the breakdown of items included and the period over which they apply.

g) Historical data on all repairs; what it cost and when, what was done, what was the underlying cause and how long was any forced outage. Data preferable over the lifetime of the unit and other similar units sufficient to get a reasonable statistical average.

h) Historical data on the replacement of any complete generator or transformer or their main components and the cause of the problem, i.e. generator rotor or stator or a complete rewind of a stator, rotor or transformer winding. Since these are infrequent events it is likely that a large number of units over a substantial period will need to be analyzed to get a reliable average incidence. Knowledge of the operating history; running hours and typical power generation and powerfactor of the units analyzed will also be required to correlate the typical component life with the power and VArs produced.

i) Cost of fuel - \$/MJ - (C_{fuel})

j) Thermodynamic efficiency of plant (not including electrical equipment) as a function of the output of the unit, P - ($\eta_{thermal}$ (P))

2.2 Data Required for Calculating VAr Related Energy Losses

While much of the fundamental data required for calculating VAr related losses is contained in 2.1 above, there is a number of additional data items which are desirable to minimize the need to rely on fixed assumptions based on typical equipment.

a) Coolant Inlet temperatures

Coolant temperatures should be a typical value or, if not known, the rated inlet temperature, usually 104 deg.F can be used

Inlet coolant temperature	- stator	(T_{a-in})
	- rotor	(T_{f-in})

b) Winding average temperatures at rated load

Temperature rises of windings at rated load should be measured values but if not known, the value appropriate to the design standards should be used, typically 158 deg.F for the stator and 176 deg. F for the rotor.

Rated temperature rises	- stator	($T_{a\text{-rated rise}}$)
	- rotor	($T_{f\text{-rated rise}}$)

c) Rotor excitation at rated load

Rotor field voltage at rated load	(V_{f-rat})

d) Rotor winding resistance

Generator rotor field winding resistance at a specified temperature, T_f

Rotor winding resistance at temp. T_f	(R_f)
Specified test temperature for R_f	(T_f)

e) Stator winding resistance

Generator stator winding d.c. resistance at a specified temperature, T_a

Stator phase resistance at temp. T_a	(R_{a-dc})
Specified test temperature for R_{a-dc}	(T_a)

Positive sequence resistance of generator stator phase

Positive sequence resistance	(R1)

f) Generator Losses

Section 3.1.1 provides an approximate breakdown of loss components in the generator but its use is not ideal. Much more preferable is an actual breakdown of losses provided as input data. Generator core losses at rated voltage are usually available from factory test results by measuring the increase in power to drive the rotor at nominal speed as excitation is increased from zero to the rated voltage condition with the stator open-circuit. Friction and windage losses are provided by the same test but with zero excitation while the stator I^2R plus stray losses are given by the increase in power to drive as excitation is increased so that rated stator current is generated when the stator is short-circuited.

Generator stator I^2R losses at rated load	($L_{a\text{-}gen\text{-}rat}$)
Generator field excitation losses at rated load	($L_{f\text{-}gen\text{-}rat}$)
Generator exciter losses at rated load	($L_{e\text{-}gen\text{-}rat}$)
Generator core losses at nominal rated voltage	($L_{i\text{-}gen\text{-}rat}$)
Generator stray losses at rated load	($L_{s\text{-}gen\text{-}rat}$)
Generator friction and windage losses	($L_{w\text{-}gen\text{-}rat}$)

g) Transformer fixed losses or part load efficiency

Transformer fixed (core) losses	($L_{t\text{-}core\text{-}rat}$)

If core losses are unknown then they can be inferred from a known Part-load efficiency of the transformer. Since the full load efficiency is known (2.1 e) above, the part-load efficiency should be at low load; typically at or below 0.5pu

Transformer part-load efficiency	(η_t)
Transformer per-unit part-load	(PU_t)

h) Transformer winding resistances and rated temperature rises

Winding resistances are used to determine the division of variable load losses between I^2R and stray losses. If not known, the inlet coolant temperature can be taken to be a nominal figure, typically 104 deg.F. Rated temperature rises of LV and HV windings are used to correct losses for winding temperature and are not very critical. If not known, assumed figures of 140 deg.F can be taken as typical for large oil-filled paper insulated transformers.

resistance of transformer LV phase at temperature $T_{t\text{-}LV}$	($R_{t\text{-}LV}$)
resistance of transformer HV phase at temperature $T_{t\text{-}HV}$	($R_{t\text{-}HV}$)
transformer coolant inlet temperature	($T_{t\text{-}in}$)
temperature of transformer LV winding appropriate to $R_{t\text{-}LV}$	($T_{t\text{-}LV}$)
temperature of transformer HV winding appropriate to $R_{t\text{-}HV}$	($T_{t\text{-}HV}$)

transformer LV winding temperature rise at rated load ($T_{t\text{-}LV\text{-}rated\text{-}rise}$)
transformer HV winding temperature rise at rated load ($T_{t\text{-}HV\text{-}rated\text{-}rise}$)

i) Unit (Auxiliary) power

Unit auxiliary electrical supplies are normally taken from the unit transformer connected to the generator main bus-bar. An estimate of the maximum unit power is required since it affects the difference between the power generated and transmitted via the step-up transformer and hence the reactance drop in the step-up transformer. In practice this power varies with load and can be approximated by a simple linear variation with power output.

Maximum power supplied to unit transformer at rated output ($P_{aux\text{-}max}$)

Power factor of the unit load at rated generation ($PF_{aux\text{-}max}$)

Power supplied to unit transformer at low load output ($P_{aux\text{-}low}$)

Low power output appropriate to the $P_{aux\text{-}low}$ value used ($P_{gen\text{-}low}$)

If a low load value of unit power is not known then a nominal reduction of (say) 20% can be assumed at half rated load. The power factor of the auxiliary load is usually about 0.8 lag. Some knowledge of the maximum unit load should be available, but would be typically around 3-5% of the generator rating for a coal-fired plant. For other plants an estimate could be found from the rating of the unit transformer.

3

COST OF VAR RELATED ENERGY LOSSES

The cost of the additional energy losses associated with generating reactive power can theoretically be determined by testing or calculation. Although data may be difficult to obtain, a calculation method is preferred. Testing the plant can be discounted since plant steam conditions are unlikely to be able to be held constant over the testing period. Since the extra losses associated with VAr generation are only of the order of 0.5-1% of the total load, inaccuracies of mechanical and electrical power measurement of 0.1% would each lead to errors of 10-20%.

Calculating the cost of VAr related energy losses can be broken down into a number of steps:

1. Analyze plant data to obtain the components of generator and transformer loss at rated load (section 3.1)

2. Calculate the generator and transformer operating conditions for a specified Power, VAr and Voltage on the HV side of the generator transformer, taking into account the transformer tapping position and reactance. (section 3.2)

3. Calculate the same operating conditions as step 2 but with VAr assumed to be zero (section 3.2)

4. Analyze generator, transformer and other loss components and hence determine the total losses for both operating conditions calculated by steps 2 and 3 (sections 3.3, 3.4 and 3.5)

5. Take the difference in losses as the additional losses due to reactive power generation (section 3.6) and calculate the cost of additional fuel required to generate these losses (section 3.7)

These steps are shown graphically in Figure 1-1 which gives an outline of the overall costing process.

3.1 Breakdown of Generator and Transformer Losses at Rated Load

Generating and transforming VArs affects the various loss components to different extents so a knowledge of the breakdown of losses is important. However, to make the methodology flexible, the starting point is an assumed loss breakdown which can be overwritten and improved upon depending upon the availability of data.

3.1.1 Generator Losses at Rated Load

Table 3-1 gives an estimate of the typical loss breakdown for turbine-type generators depending upon the type of cooling employed. The actual division of losses is highly design dependent and it would be more normal to indicate this by showing a range for each fractional loss. However, since the combination of fractional losses must always summate to one, the use of a range is inappropriate. Also it is hoped that use of supplementary information, such as winding resistances will be used subsequently to improve upon the estimates given below.

Table 3-1
Typical Breakdown of Generator Losses

COOLING METHOD	**Rotor**	**Air - indirect**	**Air - direct**	**H_2 - direct**	**H_2 - direct**
	Stator	**Air - indirect**	**Air - indirect**	**H_2 - indirect**	**H_2O - direct**
LOSS COMPONENT					
Stator I^2R	(F_a)	0.10	0.10	0.15	0.23
Rotor I^2R	(F_f)	0.12	0.16	0.28	0.3
Exciter	(F_e)	0.02	0.02	0.03	0.02
Stray load	(F_s)	0.13	0.12	0.24	0.2
Iron	(F_i)	0.16	0.15	0.13	0.08
Friction & Windage	(F_w)	0.47	0.45	0.17	0.17

Now, given the rated power of the generator, P_{rat} , and the full load efficiency, η_{rat} , then the total loss at full load, L_{rat} , is given by,

$$L_{gen\text{-}rat} = P_{gen\text{-}rat} \,.\, (100 / \eta_{gen\text{-}rat} - 1) \qquad \text{(eq. 1)}$$

Given the approximate fractional losses given in Table 3-1, the size of the various losses at full load can be estimated by multiplying the loss at rated load by the different fractional losses as:

Stator I^2R losses	$L_{a\text{-gen-rat}} = F_a \,.\, L_{gen\text{-rat}}$	(eq. 2a-f)
Rotor I^2R losses	$L_{f\text{-gen-rat}} = F_f \,.\, L_{gen\text{-rat}}$	
Exciter I^2R losses	$L_{e\text{-gen-rat}} = F_e \,.\, L_{gen\text{-rat}}$	
Stray losses	$L_{s\text{-gen-rat}} = F_s \,.\, L_{gen\text{-rat}}$	
Iron Losses	$L_{i\text{-gen-rat}} = F_i \,.\, L_{gen\text{-rat}}$	
Friction and Windage losses	$L_{w\text{-gen-rat}} = F_w \,.\, L_{gen\text{-rat}}$	

Additional information may be available to help make the loss breakdown more accurate. If a manufacturer's factory test certificate is available, or some other source, gives a clear breakdown of the actual losses at full load then these figures can be used to replace L_a ,L_f ,L_e ,L_s ,L_i and L_w and equations (4) to (12) can be ignored. Now, the rated line current, I_{rat} , is given by

$$I_{gen\text{-rat}} = P_{gen\text{-rat}} \,/\, (\, PF_{gen\text{-rat}} \,.\, \mathrm{sqrt}(3) \,.\, V_{gen\text{-rat}} \,) \qquad \text{(eq. 3)}$$

If the stator d.c. resistance, $R_{a\text{-dc}}$, is known at a temperature, T_a , then the stator I^2R loss, La at the rated temperature is,

$$L_{a\text{-gen-rat}} = 3 \,.\, R_{a\text{-dc}} \,.\, I_{gen\text{-rat}}^{\ 2} \,.\, (\, T_{a\text{-in}} + T_{a\text{-rated rise}} + 391 \,) \,/\, (\, T_a + 391 \,) \qquad \text{(eq. 4)}$$

If R1, the stator a.c. resistance is known, then this accounts for both the stator I^2R loss and the stray load loss. Hence,

$$L_{s\text{-gen-rat}} = 3 \,.\, R1 \,.\, I_{gen\text{-rat}}^{\ 2} - L_{a\text{-gen-rat}} \qquad \text{(eq. 5)}$$

If the field winding resistance, R_f , is known at a temperature, T_f , then the excitation losses at the rated temperature rise is given by,

$$L_{f\text{-gen-rat}} = I_{f\text{-rat}}^{\ 2} \,.\, R_f \,.\, (\, T_{f\text{-in}} + T_{f\text{-rated rise}} + 391) \,/\, (T_f + 391\,) \qquad \text{(eq. 6)}$$

although it may be more realistic to use a slightly higher temperature, more appropriate to normal full-load operation. Alternatively, if the field winding excitation voltage at rated load, $V_{f\text{-rat}}$, is known in addition to $I_{f\text{-rat}}$, then the excitation losses are simply,

$$L_{f\text{-}gen\text{-}rat} = V_{f\text{-}rat} \cdot I_{f\text{-}rat} \qquad \text{(eq. 7)}$$

A more accurate estimate of exciter losses can then be made by assuming a typical rated-load efficiency for the excitation system, $\eta_{ex\text{-}rat}$. For an a.c. rotating exciter, fractional efficiencies are typically 0.85 for small air-cooled generators < 50MW, 0.9 for large air-cooled generators >100MW, and 0.95 for exciters of large generators > 300MW. If a static exciter is used, its efficiency is likely to be around 95% at full load. For η_{ex} taking the appropriate value,

$$L_{e\text{-}gen\text{-}rat} = L_{f\text{-}gen\text{-}rat} \cdot (100 / \eta_{ex\text{-}rat} - 1) \qquad \text{(eq. 8)}$$

Having used equations (4 - 8) as appropriate to replace the estimated losses with accurate values, there is then a need to modify any remaining estimated loss components so that the total loss and the full load generator efficiency are not affected. The simplest way of doing this is to:

i) Add up all the loss components that are accurately known (i.e. equations 4 - 8), say L_{known}

ii) Take the loss in i) , L_{known} away from the total loss, L_{rat} , to give the remaining loss, L_{rem}

iii) Divide the remaining losses, L_{rem} , between the loss components which are still to be estimated in the same proportion as that used previously.

For example, if equations (4 - 8) have been used to identify L_a , L_f , L_e and L_s , then

$$L_{known} = L_{a\text{-}gen\text{-}rat} + L_{f\text{-}gen\text{-}rat} + L_{e\text{-}gen\text{-}rat} + L_{s\text{-}gen\text{-}rat} \qquad \text{(eq. 9)}$$

and

$$L_{rem} = L_{gen\text{-}rat} - L_{known} \qquad \text{(eq. 10)}$$

and the remaining stator iron and friction and windage loss components, $L_{i\text{-}gen\text{-}rat}$ and $L_{w\text{-}gen\text{-}rat}$, then need to be adjusted as

$$L_{i\text{-}gen\text{-}rat} = L_{rem} \cdot F_i / (F_i + F_w) \qquad \text{(eq. 11)}$$

$$L_{w\text{-}gen\text{-}rat} = L_{rem} \cdot F_w / (F_i + F_w) \qquad \text{(eq. 12)}$$

At this point the initial estimate of the generator losses at full rated load will have been improved with any available data and will be used as the basis for estimating the VAr related losses when generating at other loads.

3.1.2 Transformer Losses at Rated Load

Given the rated efficiency, $\eta_{t\text{-rat}}$, of the generator step-up transformer rated at $MVA_{t\text{-rat}}$, then the total losses at nominal voltage, $L_{t\text{-total-rat}}$, can be calculated as

$$L_{t\text{-total-rat}} = MVA_{t\text{-rat}} \cdot 10^6 \cdot (100 / \eta_{t\text{-rat}} - 1) \qquad \text{(eq. 13)}$$

This total loss figure needs to be divided into fixed (core) losses, $L_{t\text{-core-rat}}$, and variable load (copper) losses, $L_{t\text{-copper-rat}}$ i.e.

$$L_{t\text{-total-rat}} = L_{t\text{-core-rat}} + L_{t\text{-copper-rat}} \qquad \text{(eq. 14)}$$

If $L_{t\text{-core-rat}}$ is available as input data then equation (14) can be used to calculate the transformer copper losses at rated load and equations (15-18) are not required.

The absence of a known value of core losses causes a difficulty. Unfortunately the division of these losses is very dependent on transformer design so the use of assumed estimates of the fraction of losses which are fixed and variable may potentially introduce significant errors. However, in the absence of anything better

$$L_{t\text{-core-rat}} = 0.25 \cdot L_{t\text{-total-rat}} \qquad \text{(eq. 15)}$$

$$L_{t\text{-copper-rat}} = 0.75 \cdot L_{t\text{-total-rat}} \qquad \text{(eq. 16)}$$

Now, if a part load efficiency figure, η_t, is also available at a Per-Unit load, PU_t, (and if there is a choice, use a load significantly different from the rated load, say 0.5 p.u. or lower) and at the same nominal voltage, then

$$L_{t\text{-copper-rat}} = MVA_{t\text{-rat}} \cdot 10^6 \left[PU_t \cdot (100 / \eta_t - 1) + (1 - 100 / \eta_{t\text{-rat}}) \right] / (PU_t^2 - 1) \qquad \text{(eq. 17)}$$

Hence

$$L_{t\text{-core-rat}} = L_{t\text{-total-rat}} - L_{t\text{-copper-rat}} \qquad \text{(eq. 18)}$$

The variable copper loss can be assumed to be comprised of winding I^2R loss and stray losses. The relative size of these two components is dependent on individual transformer design. In the absence of winding resistance information, an approximate division is likely to be an improvement on simply assuming that all losses are resistive. In this case the rated copper loss can be assumed to be divided into the rated LV and HV winding I^2R losses, $L_{t\text{-}LV\text{-}I2R\text{-}rat}$, $L_{t\text{-}HV\text{-}I2R\text{-}rat}$, and the transformer stray losses, $L_{t\text{-}stray\text{-}rat}$ as

$$L_{t\text{-}stray\text{-}rat} = 0.3 \,.\, L_{t\text{-}copper\text{-}rat}$$

and

$$L_{t\text{-}LV\text{-}I2R\text{-}rat} = L_{t\text{-}HV\text{-}I2R\text{-}rat} = (L_{t\text{-}copper\text{-}rat} - L_{t\text{-}stray\text{-}rat}) \,/\, 2$$

However, if LV and HV winding resistances, $R_{t\text{-}LV}$ and $R_{t\text{-}HV}$, are known at temperatures $T_{t\text{-}LV}$ and $T_{t\text{-}HV}$, then, given the transformer coolant inlet temperature, $T_{t\text{-}in}$, and the LV and HV winding temperature rises at rated load, $T_{t\text{-}LV\text{-}rated\text{-}rise}$ and $T_{t\text{-}HV\text{-}rated\text{-}rise}$, the winding resistances at rated load, $R_{t\text{-}LV\text{-}rat}$ and $R_{t\text{-}HV\text{-}rat}$ are

$$R_{t\text{-}LV\text{-}rat} = R_{t\text{-}LV} \,.\, (T_{t\text{-}in} + T_{t\text{-}LV\text{-}rated\text{-}rise} + 391) \,/\, (T_{t\text{-}LV} + 391) \qquad \text{(eq. 19a)}$$

$$R_{t\text{-}HV\text{-}rat} = R_{t\text{-}HV} \,.\, (T_{t\text{-}in} + T_{t\text{-}HV\text{-}rated\text{-}rise} + 391) \,/\, (T_{t\text{-}HV} + 391) \qquad \text{(eq. 19b)}$$

hence the winding resistive losses at rated load, $L_{t\text{-}LV\text{-}I2R\text{-}rat}$ and $L_{t\text{-}HV\text{-}I2R\text{-}rat}$, are

$$L_{t\text{-}LV\text{-}I2R\text{-}rat} = 3 \,.\, I_{LV\text{-}rat}^{\;2} \,.\, R_{t\text{-}LV\text{-}rat} \qquad \text{(eq. 20a)}$$

$$L_{t\text{-}HV\text{-}I2R\text{-}rat} = 3 \,.\, I_{HV\text{-}rat}^{\;2} \,.\, R_{t\text{-}HV\text{-}rat} \qquad \text{(eq. 20b)}$$

where

$$I_{LV\text{-}rat} = I_{HV\text{-}rat} \,.\, N_{t\text{-}nom} \qquad \text{(eq. 21a)}$$

$$I_{HV\text{-}rat} = MVA_{t\text{-}rat} \times 10^6 \,/\, [\text{sqrt}(3)\, V_{t\text{-}HV\text{-}rat}] \qquad \text{(eq. 21b)}$$

hence the transformer stray losses at rated load, $L_{t\text{-}stray\text{-}rat}$, are

$$L_{t\text{-}stray\text{-}rat} = L_{t\text{-}copper\text{-}rat} - L_{t\text{-}LV\text{-}I2R\text{-}rat} - L_{t\text{-}HV\text{-}I2R\text{-}rat} \qquad \text{(eq. 22)}$$

3.2 Calculation of Generator Operating Conditions

Before being able to calculate the generator losses at a particular load condition, the operating conditions on the LV side of the generator step-up transformer must be calculated from a knowledge of the conditions on the HV side. To calculate the additional losses due to VArs, two different operating conditions need to be considered, firstly a load involving the generation of power and VAr at a specified voltage, and secondly a similar condition in which the exported VAr is assumed to be zero.

Given the rated voltage on the LV side as $V_{t\text{-}LV\text{-}rat}$, and the rated nominal voltage on the HV side, $V_{t\text{-}HV\text{-}rat}$, then the nominal turns ratio of the transformer, $N_{t\text{-}nom}$ (i.e. 22kV to 220kV transformer implies N=10), is

$$N_{t\text{-}nom} = V_{t\text{-}HV\text{-}rat} / V_{t\text{-}LV\text{-}rat} \qquad \text{(eq. 23)}$$

If the fractional tapping step be t_{step} (i.e. t_{step} = 0.01 for a 1% tapping step), and if +ve n_{tap} represents positive taps, increasing the turns ratio, then the actual turns ratio, $N_{t\text{-}actual}$, is given by

$$N_{t\text{-}actual} = N_{t\text{-}nom} (1 + n_{tap} . t_{step}) \qquad \text{(eq. 24)}$$

Now the rated current on the HV side of the transformer, $I_{HV\text{-}rat}$, is

$$I_{HV\text{-}rat} = MVA_{t\text{-}rat} / (sqrt(3) . V_{t\text{-}HV\text{-}rat}) \qquad \text{(eq. 25)}$$

The line voltage on the HV side is determined from the per-unit voltage, $V_{pu\text{-}HV\text{-}out}$, as

$$V_{HV} = V_{pu\text{-}HV\text{-}out} . V_{t\text{-}HV\text{-}rat} \qquad \text{(eq. 26a)}$$

and this voltage can be assumed to remain at the zero VAr condition (unless some other voltage is considered more realistic), hence

$$V_{HV\text{-}0Q} = V_{HV} \qquad \text{(eq. 26b)}$$

If $P_{HV\text{-}out}$ and $Q_{HV\text{-}out}$ are the real and reactive power output to the system (Q being +ve for lagging power-factor loads and -ve at leading power-factors) and $V_{pu\text{-}HV\text{-}out}$ the per-unit voltage, all at the H.V. terminals of the generator step-up transformer, then the current on the HV side is

$$I_{HV} = \mathrm{sqrt}\ (\ P_{HV\text{-}out}^{\ 2} + Q_{HV\text{-}out}^{\ 2}\ )\ /\ (\ \mathrm{sqrt}(3)\ .\ V_{HV}\ ) \qquad \text{(eq. 27a)}$$

When the reactive power, $Q_{HV\text{-}out}$, is put to zero the HV current, $I_{HV\text{-}0Q}$, is

$$I_{HV\text{-}0Q} = P_{HV\text{-}out}\ /\ (\ \mathrm{sqrt}(3)\ .\ V_{HV\text{-}0Q}\ ) \qquad \text{(eq. 27b)}$$

and the power factor angle between voltage and current, ϕ_{HV} , is

$$\phi_{HV} = \tan^{-1}(\ Q_{HV\text{-}out}\ /\ P_{HV\text{-}out}\ ) \qquad \text{(eq. 28a)}$$

and

$$\phi_{HV\text{-}0Q} = 0 \qquad \text{(eq. 28b)}$$

Note that the use of the ‘tan’ function ensures that the power factor angle is positive for lagging, positive reactive power, Q. If the transformer is operated on a tap away from nominal, the current and line voltage on the LV side of an ideal transformer will change so the conditions here, $I_{t\text{-}LV}$ an $V_{t\text{-}LV}$ and $\phi_{t\text{-}LV}$, will be

$$I_{t\text{-}LV} = I_{HV}\ .\ N_{t\text{-}actual} \qquad \text{(eq. 29a)}$$

$$I_{t\text{-}LV\text{-}0Q} = I_{HV\text{-}0Q}\ .\ N_{t\text{-}actual} \qquad \text{(eq. 29b)}$$

and

$$V_{t\text{-}LV} = V_{HV}\ /\ N_{t\text{-}actual} \qquad \text{(eq. 30a)}$$

$$V_{t\text{-}LV\text{-}0Q} = V_{HV\text{-}0Q}\ /\ N_{t\text{-}actual} \qquad \text{(eq. 30b)}$$

$$\phi_{t\text{-}LV} = \phi_{HV} \qquad \text{(eq. 31a)}$$

$$\phi_{t\text{-}LV\text{-}0Q} = 0 \qquad \text{(eq. 31b)}$$

The actual current and voltage into the generator step-up transformer is modified by the effect of transformer resistance and reactance. If the transformer is modeled by a simple series resistance and reactance, $R_{t\text{-}nom}$ and $X_{t\text{-}nom}$, then the input conditions at the LV busbar and the terminals of the generator will then become

$$I_{LV} = I_{t\text{-}LV} \qquad \text{(eq. 31a)}$$

$$I_{LV\text{-}0Q} = I_{t\text{-}LV\text{-}0Q} \qquad \text{(eq. 31b)}$$

$$V_{gen} = \text{sqrt}[\ (V_{t\text{-}LV} + \text{sqrt}(3) \,.\, I_{LV} \,.\, R_{t\text{-}nom} \,.\, \cos\phi_{t\text{-}LV} + \text{sqrt}(3) \,.\, I_{LV} \,.\, X_{t\text{-}nom} \,.\, \sin\phi_{t\text{-}LV}\ )^2 + (\ \text{sqrt}(3) \,.\, I_{LV} \,.\, R_{t\text{-}nom} \,.\, \sin\phi_{t\text{-}LV} - \text{sqrt}(3) \,.\, I_{LV} \,.\, X_{t\text{-}nom} \,.\, \cos\phi_{t\text{-}LV}\ )^2\ ] \qquad \text{(eq. 32a)}$$

$$V_{gen\text{-}0Q} = \text{sqrt}[\ (V_{t\text{-}LV} + \text{sqrt}(3) \,.\, I_{LV} \,.\, R_{t\text{-}nom} \,.\, \cos\phi_{t\text{-}LV\text{-}0Q} + \text{sqrt}(3) \,.\, I_{LV} \,.\, X_{t\text{-}nom} \,.\, \sin\phi_{t\text{-}LV\text{-}0Q})^2 + (\ \text{sqrt}(3) \,.\, I_{LV} \,.\, R_{t\text{-}nom} \,.\, \sin\phi_{t\text{-}LV\text{-}0Q} - \text{sqrt}(3) \,.\, I_{LV} \,.\, X_{t\text{-}nom} \,.\, \cos\phi_{t\text{-}LV\text{-}0Q})^2\ ] \qquad \text{(eq. 32b)}$$

where

$$R_{t\text{-}nom} = L_{t\text{-}total\text{-}rat} \ /\ [\ 3 \,.\, (\ I_{HV\text{-}rat} \,.\, N_{t\text{-}nom}\ )^2\ ] \qquad \text{(eq. 33)}$$

and

$$X_{t\text{-}nom} = X_{t\text{-}nom\text{-}pu} \,.\, V_{t\text{-}HV\text{-}rat} \ /\ [\ I_{t\text{-}HV\text{-}rat} \,.\, N_{t\text{-}nom}^{\ 2} \,.\, \text{sqrt}(3)\ ] \qquad \text{(eq. 34)}$$

Voltages V_{LV} and $V_{LV\text{-}0Q}$ represent the LV bus-bar and generator terminal voltage at the two different conditions. The power factor angles, ϕ_{LV} and , $\phi_{LV\text{-}0Q}$, are then given by

$$\phi_{LV} = \tan^{-1}[\ (\ V_{t\text{-}LV} \,.\, \sin\phi_{t\text{-}LV} + \text{sqrt}(3) \,.\, I_{t\text{-}LV} \,.\, X_t\ )\ /\ (\ V_{t\text{-}LV} \,.\, \cos\phi_{t\text{-}LV} + \text{sqrt}(3) \,.\, I_{t\text{-}LV} \,.\, R_t\ )\ ] \qquad \text{(eq. 35a)}$$

$$\phi_{LV\text{-}0Q} = \tan^{-1}[\ (\ V_{t\text{-}LV\text{-}0Q} \,.\, \sin\phi_{t\text{-}LV\text{-}0Q} + \text{sqrt}(3) \,.\, I_{t\text{-}LV\text{-}0Q} \,.\, X_t\ )\ /\ (\ V_{t\text{-}LV\text{-}0Q} \,.\, \cos\phi_{t\text{-}LV\text{-}0Q} + \text{sqrt}(3) \,.\, I_{t\text{-}LV\text{-}0Q} \,.\, R_t\ )\ ] \qquad \text{(eq. 35b)}$$

Auxiliary power requirements need to be taken into account before the generator terminal current, power and reactive power conditions can be calculated. For the required output, the auxiliary power requirements are calculated assuming a linear variation of auxiliary power defined by the input data requirements described in section 2.2 i, hence

$$P_{aux} = P_{aux\text{-}low} + (P_{aux\text{-}max} - P_{aux\text{-}low}) . (P_{HV\text{-}out} - P_{gen\text{-}low}) / (P_{gen\text{-}rat} - P_{gen\text{-}low}) \qquad \text{(eq. 36a)}$$

and the reactive auxiliary power is

$$Q_{aux} = P_{aux} . \mathrm{sqrt}(1 - PF_{aux}^{2}) / PF_{aux} \qquad \text{(eq. 36b)}$$

Auxiliary current components in-phase (real) and out-of-phase (imag.) with the generator voltage can be calculated as

$$I_{aux\text{-}real} = P_{aux} / (\mathrm{sqrt}(3) . V_{gen\text{-}rat}) \qquad \text{(eq. 37a)}$$

$$I_{aux\text{-}imag} = Q_{aux} / (\mathrm{sqrt}(3) . V_{gen\text{-}rat}) \qquad \text{(eq. 37b)}$$

Adding these components vectorially to $I_{t\text{-}LV}$ and $I_{t\text{-}LV\text{-}0Q}$ gives the generator current magnitudes

$$I_{gen} = \mathrm{sqrt}[(I_{LV} . \cos \phi_{LV} + I_{aux\text{-}real})^2 + (I_{LV} . \sin \phi_{LV} + I_{aux\text{-}imag})^2] \qquad \text{(eq. 38a)}$$

$$I_{gen\text{-}0Q} = \mathrm{sqrt}[(I_{LV\text{-}0Q} . \cos \phi_{LV\text{-}0Q} + I_{aux\text{-}real})^2 + (I_{LV\text{-}0Q} . \sin \phi_{LV\text{-}0Q} + I_{aux\text{-}imag})^2] \qquad \text{(eq. 38b)}$$

and the power factor angles ϕ_{gen} and $\phi_{gen\text{-}0Q}$ as

$$\phi_{gen} = \tan^{-1} [(I_{LV} . \sin \phi_{LV} + I_{aux\text{-}imag}) / (I_{LV} . \cos \phi_{LV} + I_{aux\text{-}real})] \qquad \text{(eq. 39a)}$$

$$\phi_{gen\text{-}0Q} = \tan^{-1} [(I_{LV\text{-}0Q} . \sin \phi_{LV\text{-}0Q} + I_{aux\text{-}imag}) / (I_{LV\text{-}0Q} . \cos \phi_{LV\text{-}0Q} + I_{aux\text{-}real})] \qquad \text{(eq. 39b)}$$

Thus the power generated at the generator terminals, P_{gen} and $P_{gen\text{-}0Q}$, is

$$P_{gen} = \mathrm{sqrt}(3) . V_{gen} . I_{gen} . \cos \phi_{gen} \qquad \text{(eq. 40a)}$$

$$P_{gen\text{-}0Q} = \mathrm{sqrt}(3) . V_{gen\text{-}0Q} . I_{gen\text{-}0Q} . \cos \phi_{gen\text{-}0Q} \qquad \text{(eq. 40b)}$$

and the reactive power generated at the generator terminals, Q_{gen} , is

$$Q_{gen} = \mathrm{sqrt}(3)\ .\ V_{gen}\ .\ I_{gen}\ .\ \sin\phi_{gen} \qquad \text{(eq. 41a)}$$

and

$$Q_{gen\text{-}0Q} = \mathrm{sqrt}(3)\ .\ V_{gen\text{-}0Q}\ .\ I_{gen\text{-}0Q}\ .\ \sin\phi_{gen\text{-}0Q} \qquad \text{(eq. 41b)}$$

The generator terminal voltage is power factor at the generator terminals is

$$PF_{gen} = P_{gen}\ /\ \mathrm{sqrt}(\ P_{gen}^{\ 2} + Q_{gen}^{\ 2}\ ) \qquad \text{(eq. 42a)}$$

and

$$PF_{gen\text{-}0Q} = P_{gen}\ /\ \mathrm{sqrt}(\ P_{gen\text{-}0Q}^{\ 2} + Q_{gen\text{-}0Q}^{\ 2}\ ) \qquad \text{(eq. 42b)}$$

3.3 Generator Losses

3.3.1 Stator I^2R Losses

If a given load is defined in terms of real and reactive power, P_{gen} and Q_{gen} , and generator line voltage, V_{gen} , then assuming a balanced 3-phase system,

$$I_{gen}^{\ 2} = (\ P_{gen}^{\ 2} + Q_{gen}^{\ 2}\ )\ /\ (\ 3\ .\ V_{gen}^{\ 2}\ ) \qquad \text{(eq. 43)}$$

Therefore the VAr related I^2R losses, $L_{a\text{-}q}$, in a 3-phase winding with constant resistance, R_a , at the same voltage can be seen to be,

$$L_{a\text{-}q} = R_a\ .\ Q_{gen}^{\ 2}\ /\ V_{gen}^{\ 2} \qquad \text{(eq. 44)}$$

Unfortunately this simple approach does not take account of differences in generator terminal voltage as a result of the change in power factor. Also the resistance of machine windings are not constant and the temperature effect can lead to losses changing by 4% for every 50 deg.F rise. To take this effect into account, the assumption can be made that the winding temperature rise is proportional to the I^2R loss. Given the inlet coolant temperature to the stator, $T_{a\text{-}in}$, and the temperature rise of the stator winding at rated load, $T_{a\text{-}rated\ rise}$, then the stator winding temperature, T_a, and resultant resistance, $R_{a\text{-}T}$, can be related to the stator winding loss at rated load, $L_{a\text{-}gen\text{-}rat}$. An estimate of temperature of the winding is then given by,

$$T_a = T_{a\text{-in}} + T_{a\text{-rated rise}} \;.\; 3 \;.\; I_{gen}^{\;2} \;.\; R_{a\text{-T}} \;\; / \; L_{a\text{-gen-rat}} \qquad \text{(eq. 45)}$$

Now the resistance of the winding at the standard 68 deg.F, $R_{a\text{-dc@68 deg}}$, can be calculated from $L_{a\text{-gen-rat}}$ as

$$R_{a\text{-dc@68 deg}} = 459 \;.\; L_{a\text{-gen-rat}} \;/\; [\; 3 \;.\; I_{gen\text{-rat}}^{\;2} \;.\; (T_{a\text{-in}} + T_{a\text{-rated rise}} + 391\;)\;] \qquad \text{(eq. 46)}$$

Now at a temperature, T_a , the stator winding resistance is

$$R_{a\text{-T}} = R_{a\text{-dc@68 deg}} \;.\; (\; T_a + 391\;) \;/\; 459 \qquad \text{(eq. 47)}$$

Combining equations (45,46 and 47) and rearranging in terms of $R_{a\text{-t}}$, gives the actual stator I^2R loss, taking account of the effect of temperature on R_a, as

$$\begin{aligned} L_a &= 3 \;.\; I_{gen}^{\;2} \;.\; R_{a\text{-T}} \\ &= I_{gen}^{\;2} \;.\; L_{a\text{-gen-rat}} \;.\; (\; T_{a\text{-in}} + 391\;) \;/\; [\; I_{gen\text{-rat}}^{\;2} \;.\; (\; T_{a\text{-in}} + T_{a\text{-rated rise}} + 391\;) \\ &\quad - T_{a\text{-rated rise}} \;.\; I_{gen}^{\;2} \;] \end{aligned} \qquad \text{(eq. 48)}$$

3.3.2 Rotor I^2R Losses

The rotor excitation losses are very significantly affected by VAr, with excitation currents increasing at lagging loads. The first step is to develop a method for predicting the field excitation current, I_f , for a particular real and reactive power (whether leading or lagging) at the generator terminals, $P_{gen,}$ and Q_{gen} , and terminal line voltage, V_{gen} . Excitation calculations need to take the effects of magnetic saturation into effect and the easiest way that this can be accomplished is to use information from the open-circuit saturation characteristic of the machine. The following is a method of calculating excitation based on IEEE Std. 1110-1991, but modified to be applicable to solid round-rotor turbine-type generators and salient pole generators.

3.3.2.1 Open-Circuit Saturation Characteristic.

While it is possible to use the O.C. curve directly, it is more convenient to fit a simple mathematical equation to the curve so that excitation calculations can be developed on a simple spreadsheet. The equation to be fitted is of the form:

$$I_f = A \;.\; V + B \;.\; V^n \qquad \text{(eq. 49)}$$

The term " A . V " represents the air-gap line and the " B . V^n" term the additional current due to saturation. Only three points are required to fit the curve. Let:

I_f (1) , V(1) be on the air-gap line (at approx. rated volts)
I_f (2) , V(2) be at the rated open-circuit (1.0 p.u.) voltage
I_f (3) , V(3) be a point at approx. 1.2 or 1.3 p.u. voltage

If the above points are not available, an approximate and typical saturation curve can be assumed by making:

$I_f(1) = I_{f\text{-}oc} \cdot 10 / 11$	$V(1) = V_{gen\text{-}rat}$
$I_f(2) = I_{f\text{-}oc}$	$V(2) = V_{gen\text{-}rat}$
$I_f(3) = 1.3 \cdot V(3) \cdot I_f(1)$	$V(3) = 1.2 \cdot V_{gen\text{-}rat}$

However, this assumption is not ideal and it is expected that the above data points should be available.

Using these points, equation (49) can be fitted if:

$$A = I_f(1) / V(1) \qquad \text{(eq. 50)}$$

$$n = \ln \{ (I_f(2) - I_f(1) \cdot V(2) / V(1)) / (I_f(3) - I_f(1) \cdot V(3) / V(1)) \} / \ln \{ V(2) / V(3) \} \qquad \text{(eq. 51)}$$

$$B = \{ I_f(3) - I_f(1) \cdot V(3) / V(1) \} / V(3)^n \qquad \text{(eq. 52)}$$

The curve fit is surprisingly good over the range required for excitation calculations. It also has the advantage that the component of current that deviates from the air-gap line, required in the calculations, $I_{f\text{-}sat}$, is simply

$$I_{f\text{-}sat} = B \cdot V^n \qquad \text{(eq. 53)}$$

3.3.2.2 Voltage Behind Potier Reactance and Effect of Saturation.

The Potier Reactance, Xp, can be measured from zero-power factor excitation tests but, for the purposes of calculating rotor field excitation it will be sufficient to take one of the standard design approximation for Xp as,

$$Xp_{pu} = 0.8 \cdot Xd_{pu}^{/} \qquad \text{(eq. 54)}$$

or $\quad Xp_{pu} = Xl_{pu} + 0.63 \cdot (Xd_{pu}^{/} - Xl_{pu})$

and $\quad Xp = V_{gen\text{-}rat} \cdot Xp_{pu} \, / \, (\text{sqrt}(3) \cdot I_{gen\text{-}rat})$ (eq. 55)

Figure 3-1 shows the phasor diagram for the synchronous machine and the internal voltage, V_{int} , which is given by,

$$V_{int} = \text{sqrt} \left[(V_{gen} \cdot \cos PF_{gen})^2 + (V_{gen} \cdot \sin PF_{gen} + \text{sqrt}(3) \cdot I_{gen} \cdot Xp)^2 \right] \quad \text{(eq. 56)}$$

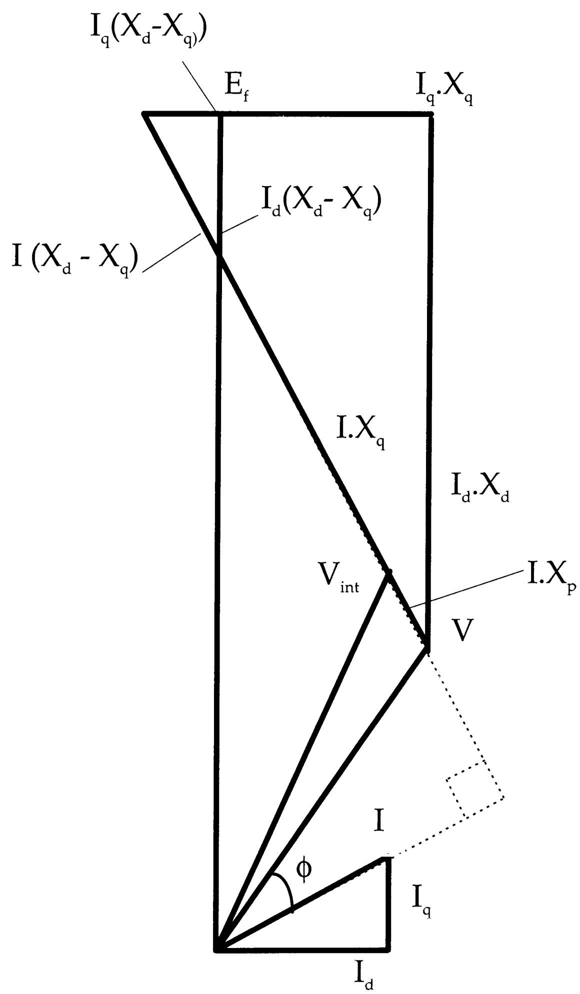

Figure 3-1
Phasor diagram of synchronous generator.

This internal voltage, V_{int} , can be used in equation 53 to calculate the extra field excitation, $I_{f\text{-}sat}$, which would be required due to saturation if this voltage were generated open-circuit.

$$I_{f\text{-}sat} = B \, . \, V_{int}^{\;n} \qquad \text{(eq. 57)}$$

3.3.2.3 Excitation Calculation.

In general the d- and q-axis synchronous reactances of a generator are different and Figure 3-1 shows this condition. For round-rotor turbine type generators the d- and q-axis reactances are virtually identical, a good approximation for the unsaturated q-axis reactance being

$$Xq = 0.97 \, . \, Xd \qquad \text{(eq. 58)}$$

This approximation is sufficient for round-rotor machines but accurate knowledge of Xq will be required for salient pole generators. For the more general case shown by the phasor diagram in Figure 3-1,

$$Iq = I_{gen} \, . \, V_{gen} \, . \, \cos \phi_{gen} \; / \; \text{sqrt} \, [\, (V_{gen} \, . \, \cos \phi_{gen})^2 + (V_{gen} \, . \, \sin \phi_{gen} + \text{sqrt}(3) \, . \, I_{gen} \, . \, Xq)^2 \,] \qquad \text{(eq. 59)}$$

$$Id = I_{gen} \, . \, (V_{gen} \, . \, \sin \phi_{gen} + \text{sqrt}(3) \, . \, I_{gen} \, . \, Xq) \; / \; \text{sqrt} \, [\, (V_{gen} \, . \, \cos \phi_{gen})^2 + (V_{gen} \, . \, \sin \phi_{gen} + \text{sqrt}(3) \, . \, I_{gen} \, . \, Xq)^2 \,] \qquad \text{(eq. 60)}$$

and

$$E_f = \text{sqrt} \, [\, (V_{gen} \, . \, \cos \phi_{gen})^2 + (V_{gen} \, . \, \sin \phi_{gen} + \text{sqrt}(3) \, . \, I_{gen} \, . \, Xq)^2 \,] + \text{sqrt}(3) \, . \, Id \, . \, (Xd - Xq) \qquad \text{(eq. 61)}$$

The field excitation would normally be given by scaling field current required for rated voltage on the air-gap line, $I_{f\text{-}ag}$ (= A $V_{gen\text{-}rat}$), by the ratio $E_f/V_{gen\text{-}rat}$ and then adding on the contribution, $I_{f\text{-}sat}$, from equation 57,

$$I_{f\text{-}uncorrected} = I_{f\text{-}ag} \, . \, E_f \; / \; V_{gen\text{-}rat} \; + I_{f\text{-}sat} \qquad \text{(eq. 62)}$$

The method adopted here is essentially that described in reference.[3] However, it has been found by others that a more accurate prediction can be made by multiplying the field excitation by a correction factor, K_{sat} , which has the form shown in Figure 3-2. (Note: this improvement is probably due to the fact that $I_{f\text{-}sat}$ is calculated from the open-circuit curve and will therefore underestimate the saturation effect at high lagging loads when the field excitation is much higher and increased saturation occurs due to additional field leakage flux.)

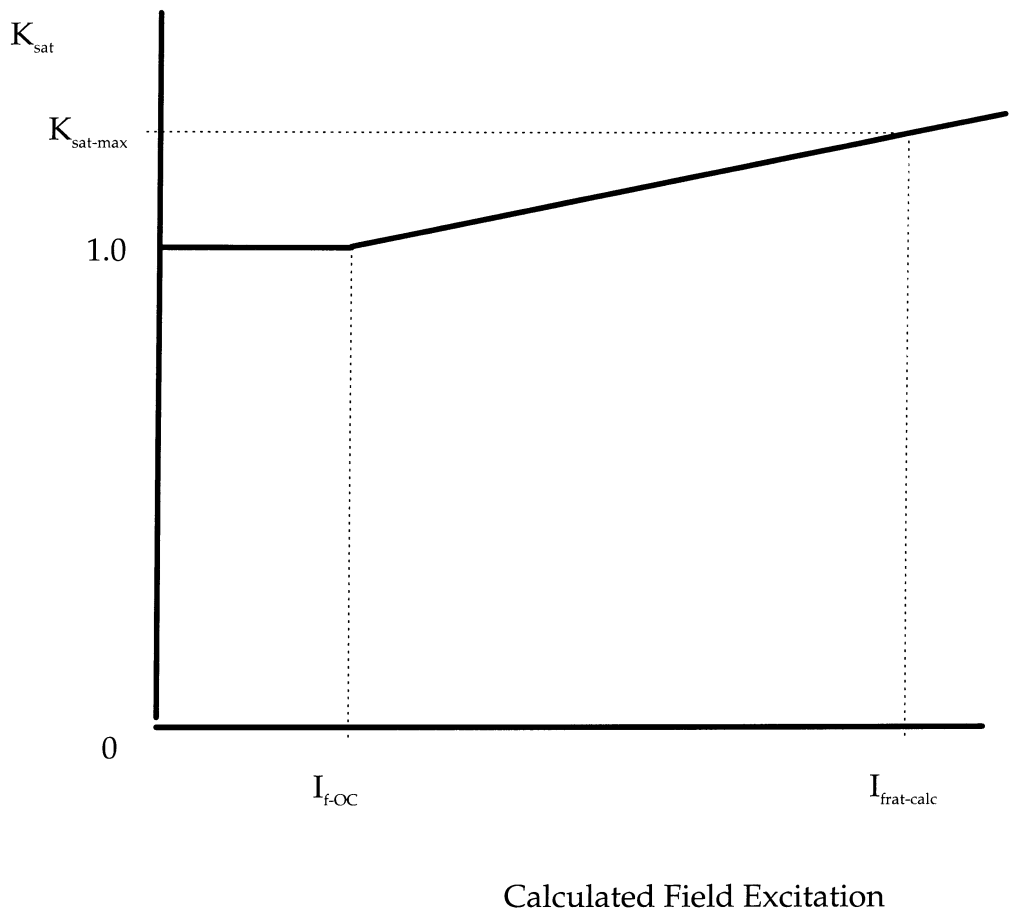

Figure 3-2
Field excitation correction factor.

If K_{sat} is calculated, based on the known rated excitation of the machine at rated output, it has the advantage of reducing any errors to very small proportions in the region where excitation losses are greatest thus minimizing overall errors in subsequent calculations. Using equations 58 to 62 to calculate a rated field current, $I_{f\text{-}rat\text{-}calc}$, for the operating condition, $V_{gen\text{-}rat}$, $I_{gen\text{-}rat}$ and $\phi_{gen\text{-}rat} = \cos^{-1} PF_{gen\text{-}rat}$, then $K_{sat\text{-}max}$ is given by

$$K_{sat\text{-}max} = I_{f\text{-}rat} \ / \ I_{f\text{-}rat\text{-}calc} \qquad \text{(eq. 63)}$$

Usually $K_{sat\text{-}max}$ is in the region 1.0 to 1.1. The correction factor K_{sat} is then calculated by linear interpolation between the K_{sat} = 1.0 and $K_{sat\text{-}max}$. When $I_{f\text{-}uncorrected} > I_{f\text{-}oc}$ then

$$K_{sat} = 1.0 + (K_{sat\text{-}max} - 1.0) . (I_{f\text{-}uncorrected} - I_{f\text{-}oc}) \ / \ (I_{f\text{-}rat\text{-}calc} - I_{f\text{-}oc}) \qquad \text{(eq. 64)}$$

and corrected field excitation is then given by

if $I_{f\text{-}uncorrected} > I_{f\text{-}oc}$ then

$$I_f = I_{f\text{-}uncorrected} \ . \ K_{sat} \qquad \text{(eq. 65a)}$$

if $I_{f\text{-}uncorrected} < I_{f\text{-}oc}$ then K_{sat} = 1 and

$$I_f = I_{f\text{-}uncorrected} \qquad \text{(eq. 65b)}$$

3.3.2.4 Excitation Loss Calculation Allowing for Winding Temperature Variation.

Since the rated excitation losses, $L_{f\text{-}gen\text{-}rat}$, rated excitation, $I_{f\text{-}rat}$, coolant inlet temperature, $T_{f\text{-}in}$, and the rated winding temperature rise, $T_{f\text{-}rated\text{-}rise}$ are known, the winding resistance at 68 deg.F can be calculated as

$$R_{f\text{-}68} = L_{f\text{-}gen\text{-}rat} \ . \ 459 \ / \ [\ I_{f\text{-}rat}^{2} \ . \ (\ T_{f\text{-}in} + T_{f\text{-}rated\text{-}rise} + 391) \ ] \qquad \text{(eq. 66)}$$

Excitation losses, L_f , are a function of excitation current and resistance and, since resistance is a function of winding temperature, T_f , then

$$L_f = I_f^2 \ . \ R_{f\text{-}68} \ . \ (\ T_f + 391 \ ) \ / \ 459 \qquad \text{(eq. 67)}$$

and, if a similar assumption is made to that used in section 3.3.1, namely that winding temperature rise is proportional to total winding losses,

$$T_f = T_{f\text{-}in} + L_f \ . \ T_{f\text{-}rated\text{-}rise} \ / \ L_{f\text{-}gen\text{-}rat} \qquad \text{(eq. 68)}$$

then by rearranging equations 66-68, the losses at a specified field current can be calculated as

$$L_f = I_f^2 \ . L_{f\text{-}gen\text{-}rat} \ . \ (\ T_{f\text{-}in} + 391 \ ) \ / \ [\ I_{f\text{-}rat}^{2} \ . \ (\ T_{f\text{-}in} + T_{f\text{-}rated\text{-}rise} + 391) - I_f^2 \ . \ T_{f\text{-}rated\text{-}rise} \ ] \qquad \text{(eq. 69)}$$

3.3.3 Stray Load Losses

Stray load losses are the result of a combination of eddy currents induced in windings, stator frame structure, rotor, stator core ends and other conducting components by stray fields and some additional iron losses caused by armature reaction leakage fields. The losses are proportional to I_a^2. It is impractical to take into account any temperature effect since skin-depth (inductance) limited eddy currents are proportional to material resistivity while resistance-limited eddy currents, also present, are inversely proportional to material resistivity. Since the split in different types of losses is design dependent, cannot be known without significant design knowledge and analysis and, to a first approximation, tend to cancel out the effect of temperature, these effects are ignored. As a result the losses, L_s , are given by

$$L_s = L_{s\text{-gen-rat}} \,.\, I_{LV}^2 \;/\; I_{gen\text{-rat}}^2 \qquad \text{(eq. 70)}$$

3.3.4 Iron Losses

Losses above the fixed friction and windage component which occur when the generator is excited but not synchronized are described as iron losses: they are primarily due to hysteresis and eddy currents induced by the open-circuit flux in the stator laminated iron core. Eddy-current losses are proportional to the square of flux density while hysteresis losses tend to increase with a slightly lower power; the net effect being that iron losses increase with core flux levels to a power of about 1.8. Assuming factory test information (power to drive on open-circuit) is not available to fit this variation precisely, then a reasonable assumption is that the iron loss component is dependent on generator terminal voltage as

$$L_i = L_{i\text{-gen-rat}} \;(V_{LV} \;/\; V_{gen\text{-rat}})^{1.8} \qquad \text{(eq. 71)}$$

In practice the core flux densities may be more accurately determined by calculating an internal voltage taking account of the stator end-leakage reactance, but this reactance is quite small (typically 0.04 pu) and can be ignored. This approximation is in accordance with the method of determining generator on-load efficiency and in accounting for iron losses given in international standards.

3.3.5 Windage Losses

Windage losses are normally grouped together with bearing and seal losses and assumed to be constant. This is the approach favored here. However, if the generator is hydrogen cooled, it is possible that the generator gas pressure can be reduced so that it is just within its rating at unity powerfactor. Increasing the gas pressure to generate VArs then causes an increase in the windage.

Since windage loss proportional to gas pressure, the losses attributable to a VAr capability are

$$L_{w\text{-}q} = L_{w\text{-}gen\text{-}rat} \,.\, (P_{norm} - P_{reduced}) \,/\, P_{norm} \qquad \text{(eq. 72)}$$

where $L_{w\text{-}gen\text{-}rat}$ is the windage loss at rated gas pressure, P_{norm} , and $P_{reduced}$ is the reduced gas pressure at unity power-factor. Application of this simple equation requires that the reduced gas pressure, capable of giving the same critical hot-spot temperatures as at rated load, is known. What should be remembered is that by allowing the winding temperatures to increase, presumably back to the rated temperatures, the benefit of lower winding resistances is lost and this may counteract the benefit of reduced windage losses. If this is required, the temperature enhancement effect must be removed from the calculation of field and stator losses and this can be achieved by artificially putting $T_{a\text{-}rated\text{-}rise}$ and $T_{f\text{-}rated\text{-}rise}$ to be equal to $T_{a\text{-}in}$ and $T_{f\text{-}in}$ respectively in equations 48 and 69.

3.3.6 Exciter Losses

Rotating exciter losses are relatively small and can be assumed to be made up of a fixed loss, due to friction and windage, and a variable loss proportional to I_f^2. The proportion of the exciter losses at rated load which are fixed, $F_{e\text{-}fx}$, can be assumed to be about 0.5 unless specific exciter data is available. In this case the exciter losses are given by

$$L_e = L_{e\text{-}gen\text{-}rat} \,.\, [F_{e\text{-}fx} + (1 - F_{e\text{-}fx}) \,.\, I_f^2 \,/\, I_{f\text{-}rat}^{\ 2}] \qquad \text{(eq. 73)}$$

Given the small effect this loss has on the total, it is probable that static exciter systems can also use this equation: clearly the value given to $F_{e\text{-}fx}$ can be adjusted to provide a reasonable approximation if the information on convertor and transformer efficiency are known.

3.4 Transformer Losses

Section 3.1.2 describes the way in which the transformer losses at rated load can be split into fixed core losses, $L_{t\text{-}core\text{-}rat}$, and variable copper (including stray) losses, $L_{t\text{-}copper\text{-}rat}$, and, depending on whether winding resistances are known, the resistive and stray losses. Using these full-load loss components it is then possible to calculate the losses at any intermediate load.

3.4.1 Winding I^2R Losses

Assuming that the winding temperature rise is proportional to the I^2R loss, then, by a similar analysis as that used to calculate the effect of temperature on resistance used to calculate generator stator and rotor I^2R losses (equations 48 and 69), the winding resistive losses, $L_{t\text{-}LV\text{-}I2R}$ and $L_{t\text{-}HV\text{-}I2R}$, at any other load condition are

$$L_{t\text{-}LV\text{-}I2R} = I_{LV}^2 \,.\, L_{t\text{-}LV\text{-}I2R\text{-}rat} \,.\, (T_{t\text{-}in} + 391) / [I_{LV\text{-}rat}^2 \,.\, (T_{t\text{-}in} + T_{t\text{-}LV\text{-}rat\text{-}rise} + 391) - T_{t\text{-}LV\text{-}rat\text{-}rise} \,.\, I_{LV}^2] \quad \text{(eq. 74a)}$$

$$L_{t\text{-}HV\text{-}I2R} = I_{HV}^2 \,.\, L_{t\text{-}HV\text{-}I2R\text{-}rat} \,.\, (T_{t\text{-}in} + 391) / [I_{HV\text{-}rat}^2 \,.\, (T_{t\text{-}in} + T_{t\text{-}HV\text{-}rat\text{-}rise} + 391) - T_{t\text{-}HV\text{-}rat\text{-}rise} \,.\, I_{HV}^2] \quad \text{(eq. 74b)}$$

3.4.2 Stray Losses

Stray losses cannot be split into HV and LV components and can be conveniently related to either HV or LV current. Generally stray losses are caused by localized eddy currents in the winding conductors. Conductor strands are dimensioned such that these eddy currents operate in the “resistance limited” mode such that the effect of higher loads and winding temperatures, increases the resistance, lowers the eddy current density and results in the stray loss reducing. The stray load loss at rated load can be scaled, in terms of current and resistance, to give the stray loss at a different load, $L_{t\text{-}stray}$, as

$$L_{t\text{-}stray} = L_{t\text{-}stray\text{-}rat} \,.\, (I_{LV} / I_{LV\text{-}rat})^2 \,.\, (R_{t\text{-}LV\text{-}rat} / R_{t\text{-}LV\text{-}T}) \quad \text{(eq. 75)}$$

Since stray losses cannot be split easily between HV and LV windings and there is a natural balance in current between the two windings, the loss is scaled in terms of the conditions prevailing in the LV winding. Equation (75) cannot be used directly since the resistance of the winding, $R_{t\text{-}LV\text{-}T}$, at an intermediate temperature is not known. However if the assumption is made that the winding temperature rise is predominately due to and proportional to the I^2R loss in the winding then by some algebraic manipulation

$$R_{t\text{-}LV\text{-}T} = L_{t\text{-}LV\text{-}I2R\text{-}rat} \,.\, (T_{t\text{-}in} + 391) / \{ 3 \,.\, [I_{LV\text{-}rat}^2 \,.\, (T_{t\text{-}in} + T_{t\text{-}LV\text{-}rated\ rise} + 391) - T_{t\text{-}LV\text{-}rated\ rise} \,.\, I_{LV}^2] \} \quad \text{(eq. 76)}$$

$$T_{t\text{-}LV\text{-}rise} = T_{t\text{-}LV\text{-}rated\ rise} \,.\, I_{LV}^{2} \,.\, (\, T_{t\text{-}in} + 391\,) \,/\, [\, I_{LV\text{-}rat}^{2} \,.\, (T_{t\text{-}in} + T_{t\text{-}LV\text{-}rated\ rise} + 391\,) - T_{t\text{-}LV\text{-}rated\ rise} \,.\, I_{LV}^{2}\,)\,] \quad \text{(eq. 77)}$$

Combining equations 75, 76 and 77 gives the stray load loss compensated for temperature changes, $L_{t\text{-}stray}$, as

$$L_{t\text{-}stray} = L_{t\text{-}stray\text{-}rat} \,.\, (\, I_{LV} \,/\, I_{LV\text{-}rat}\,)^{2} \,.\, [\, I_{LV\text{-}rat}^{2} \,.\, (\, T_{t\text{-}in} + T_{t\text{-}LV\text{-}rated\ rise} + 391\,) - T_{t\text{-}LV\text{-}rated\ rise} \,.\, I_{LV}^{2}\,] \,/\, [\, I_{LV\text{-}rat}^{2} \,.\, (\, T_{t\text{-}in} + 391\,)\,] \quad \text{(eq. 78)}$$

3.4.3 Iron Losses

Transformer iron losses can be assumed to vary as a function of core flux density and hence voltage. Core losses at rated load can therefore be scaled to give the core iron loss at different operating conditions, $L_{t\text{-}core}$, as

$$L_{t\text{-}core} = L_{t\text{-}core\text{-}rat} \,.\, [\, (\, V_{t\text{-}LV} + V_{t\text{-}HV} \,/\, N_{t\text{-}actual}\,) \,/\, (\, V_{t\text{-}LV\text{-}rat} + V_{t\text{-}HV\text{-}rat} \,/\, N_{t\text{-}nom}\,)\,]^{1.8} \quad \text{(eq. 79)}$$

3.5 Miscellaneous Other Losses

Usually it will be sufficient to analyze generator, transformer and exciter losses only since these will normally account for virtually all the VAr related electrical losses. However, while losses in switchgear can be ignored, losses in an abnormal length of LV bus-bar may be worth tacking into account. In general, if the effective ac phase resistance of an item of equipment is $R_{ph\text{-}ac}$ then the total loss at rated load, $L_{misc\text{-}rat}$, is

$$L_{misc\text{-}rat} = 3 \,.\, I_{LV\text{-}rat}^{2} \,.\, R_{ph\text{-}ac} \quad \text{(eq. 80)}$$

To get some idea as to whether a length of copper bus-bar does give significant losses, the dc resistance at a standard 167 deg.F, $R_{dc\text{-}167}$, can be calculated as

$$R_{dc\text{-}167} = \rho_{copper} \,.\, Lgth \,.\, (167 + 391\,) \,/\, (\, Area \,.\, 459)$$

where ρ_{copper} = resistivity of copper at 68 deg.F (Ohm-metres)

Lgth = bus bar length (m)

Area = bus bar cross-sectional area (m^2)

The ratio of R_{ac} / R_{dc} may introduce a factor of x2.

Given the small contribution of these other losses, correcting losses for temperature is not thought to be necessary. In this case the miscellaneous equipment loss, L_{misc} , at some other load condition is

$$L_{misc} = L_{misc\text{-}rat} \cdot (I_{LV} \ / \ I_{LV\text{-}rat})^2 \qquad \text{(eq. 81)}$$

3.6 Calculation of VAr Related Energy Losses

Where losses are taken to be proportional to current squared, the VAr related losses can be calculated in an approximate way by multiplying the loss at rated load simply by the factor $Q^2/(P_{rat}^{\ 2} + Q_{rat}^{\ 2})$. However this does not take account of resistance changes with temperature or different voltage conditions and certainly does not account for generator excitation losses. To take these factors into account, the equations given above could be combined to give a single equation for each loss but the resulting formula would each be large, complicated and difficult to check. A more practical method is to use the equations in a software spreadsheet so that the losses and costs for a range of operating conditions and durations can be calculated.

Section 3.2 shows how the operating conditions for the load condition, with and without VAr generation, can be calculated in terms of P_{out} , Q_{out} , and $V_{pu\text{-}HV\text{-}out}$: the following table summarizes the symbols and equations used.

Table 3-2
Summary of Symbols and Equations for Operating Conditions

	LEADING OR LAGGING CONDITION		ZERO VAr CONDITION	
Quantity	**Symbol**	**Eqn.**	**Symbol**	**Eqn.**
Transformer HV Phase current	I_{HV}	27a	$I_{HV\text{-}0Q}$	27b
Transformer LV Phase current	I_{LV}	29a/31a	$I_{LV\text{-}0Q}$	29b/31b
Generator phase current	I_{gen}	38a	$I_{gen\text{-}0Q}$	38b
Power output of generator	P_{gen}	40a	$P_{gen\text{-}0Q}$	40b
Reactive output of generator (+ve lagging, -ve leading)	Q_{gen}	41a	$Q_{gen\text{-}0Q}$	41b
Generator LV terminal line voltage	V_{gen}	32a	$V_{gen\text{-}0Q}$	32b
Generator Power factor angle (+ve lagging, -ve leading)	ϕ_{gen}	39a	$\phi_{gen\text{-}0Q}$	39b

If equations 43 to 81 are used to calculate the loss components for both normal and zero VAr conditions to give losses L_a and $L_{a\text{-}0Q}$, L_f and $L_{f\text{-}0Q}$ etc. then the VAr related loss components $L_{a\text{-}q}$ and $L_{f\text{-}q}$ are:

a) Generator stator I^2R loss (equation 48) $L_{a\text{-}q} = L_a - L_{a\text{-}0Q}$ (eq. 82a)

b) Generator field excitation I^2R loss (equation 69) $L_{f\text{-}q} = L_f - L_{f\text{-}0Q}$ (eq. 82b)

c) Generator stray losses (equation 70) $L_{s\text{-}q} = L_s - L_{s\text{-}0Q}$ (eq. 82c)

d) Generator iron losses (equation 71) $L_{i\text{-}q} = L_i - L_{i\text{-}0Q}$ (eq. 82d)

e) Generator exciter loss (equation 73) $L_{e\text{-}q} = L_e - L_{e\text{-}0Q}$ (eq. 82e)

f) Transformer LV I^2R loss (equation 74a) $L_{t\text{-}LV\text{-}I2R\text{-}q} = L_{t\text{-}LV\text{-}I2R} - L_{t\text{-}LV\text{-}I2R\text{-}0Q}$ (eq. 82f)

g) Transformer HV I^2R loss (equation 74b) $L_{t\text{-}HV\text{-}I2R\text{-}q} = L_{t\text{-}HV\text{-}I2R} - L_{t\text{-}HV\text{-}I2R\text{-}0Q}$ (eq. 82g)

h) Transformer stray loss (equation 78) $L_{t\text{-}stray\text{-}q} = L_{t\text{-}stray} - L_{t\text{-}stray\text{-}0Q}$ (eq. 82h)

i) Transformer iron loss (equation 79) $L_{t\text{-}core\text{-}q} = L_{t\text{-}core} - L_{t\text{-}core\text{-}0Q}$ (eq. 82i)

j) Miscellaneous other losses (equation 81) $L_{misc\text{-}q} = L_{misc} - L_{misc\text{-}0Q}$ (eq. 82j)

The total VAr related loss, $L_{total\text{-}q}$, is therefore

$$L_{total\text{-}q} = L_{a\text{-}q} + L_{f\text{-}q} + L_{s\text{-}q} + L_{i\text{-}q} + L_{e\text{-}q} + L_{t\text{-}LV\text{-}I2r\text{-}q} + L_{t\text{-}HV\text{-}I2R\text{-}q} + L_{t\text{-}stray\text{-}q} + L_{t\text{-}core\text{-}q} + L_{t\text{-}misc\text{-}q} \quad \text{(eq. 83)}$$

3.7 Cost of VAr Related Energy Losses

Having calculated the additional losses associated with the generation of reactive power, the cost of the additional fuel required to generate the losses can be deduced. The form of the overall thermal efficiency of the plant (not including electrical losses) is dominated by the turbine no-load heat loss (which, when adjusted to standard conditions, can be determined from the Willans line, a straight line relationship between turbine heat consumption and generated load) and the overall incremental heat-rate of the thermodynamic cycle, η_{cycle}. Given a mechanical output power, P, and turbine no-load losses, L_{turb} , the plant overall thermal efficiency is approximately characterized by

$$\eta_{thermal} = P \cdot \eta_{cycle} \; / \; (P + L_{turb}) \qquad \text{(eq. 84)}$$

If two overall plant thermal efficiencies, $\eta_{thermal\text{-}1}$ and $\eta_{thermal\text{-}2}$, are known at two mechanical power outputs, P_1 and P_2 , then it can be shown that

$$L_{turb} = P_1 \cdot P_2 \cdot (\eta_{thermal\text{-}1} - \eta_{thermal\text{-}2}) \; / \; (P_1 \cdot \eta_{thermal\text{-}2} - P_2 \cdot \eta_{thermal\text{-}1}) \qquad \text{(eq. 85)}$$

and

$$\eta_{cycle} = \eta_{thermal\text{-}1} \cdot [\, 1 + P_2 \cdot (\eta_{thermal\text{-}1} - \eta_{thermal\text{-}2}) \; / \; (P_1 \cdot \eta_{thermal\text{-}2} - P_2 \cdot \eta_{thermal\text{-}1}) \,] \qquad \text{(eq. 86)}$$

Since the turbine losses are assumed to be constant, increases in the mechanical shaft power required to overcome any additional VAr related losses, $L_{total\text{-}q}$, are only affected by the plant incremental heat rate, η_{cycle} , hence, over a period of generation, t, the cost of additional fuel is therefore

$$C_q = L_{total\text{-}q} \cdot t \cdot C_{fuel} \cdot 10^{-6} \; / \; \eta_{cycle} \qquad \text{(eq. 87)}$$

Thus, at a particular electrical operating point, the cost of VAr related losses, C_q, can be calculated over a defined period of operation. To obtain the cost of generating VAr over a longer period in which generation fluctuates, it is necessary to adopt a numerical approach since the non-linearities in the cost terms preclude a more elegant mathematical approach. The period of generation must therefore be divided up into separate (representative/average) electrical operating points and durations of operation. Taking a simple case as an example; the calculation of the cost of VAr generated over a year, where full load and 0.85 lag power factor is generated for 60% of the year, for 20% of the year the power factor reduces to 0.9 lag and, for the last 20%, load is reduced to 80% of the maximum rating and power factor is 0.95 lag. Equation (87) is used to calculate the costs of VAr generation for each of these loads (C_{q1} , C_{q2} ,C_{q3} etc. over generation periods t_1 , t_2 , t_3 etc.) and the total cost is given by the simple addition of C_{q1} , C_{q2} , C_{q3}. Complex schedules of generation and periods of operation can be analyzed in this way fairly easily using a spreadsheet to summate the individual cost components.

As an alternative, it is possible to use the methodology to calculate the variable cost of VAr related energy losses, as a function of reactive power output, at a number of different levels of generated real power. A typical graph of this type is shown in Figure 3-3 and shows how the excess fuel cost varies as a function of reactive power. The non-linear nature of the costs (which are linearly related to the VAr related electrical losses) is evident as is the fact that costs, by definition, become zero at unity power-factor. Also shown is the fact that, due to the effect of generator excitation losses, VAr related losses become a minimum at small leading power-factors, creating a very small negative cost (i.e. a cost benefits) when operating in this region.

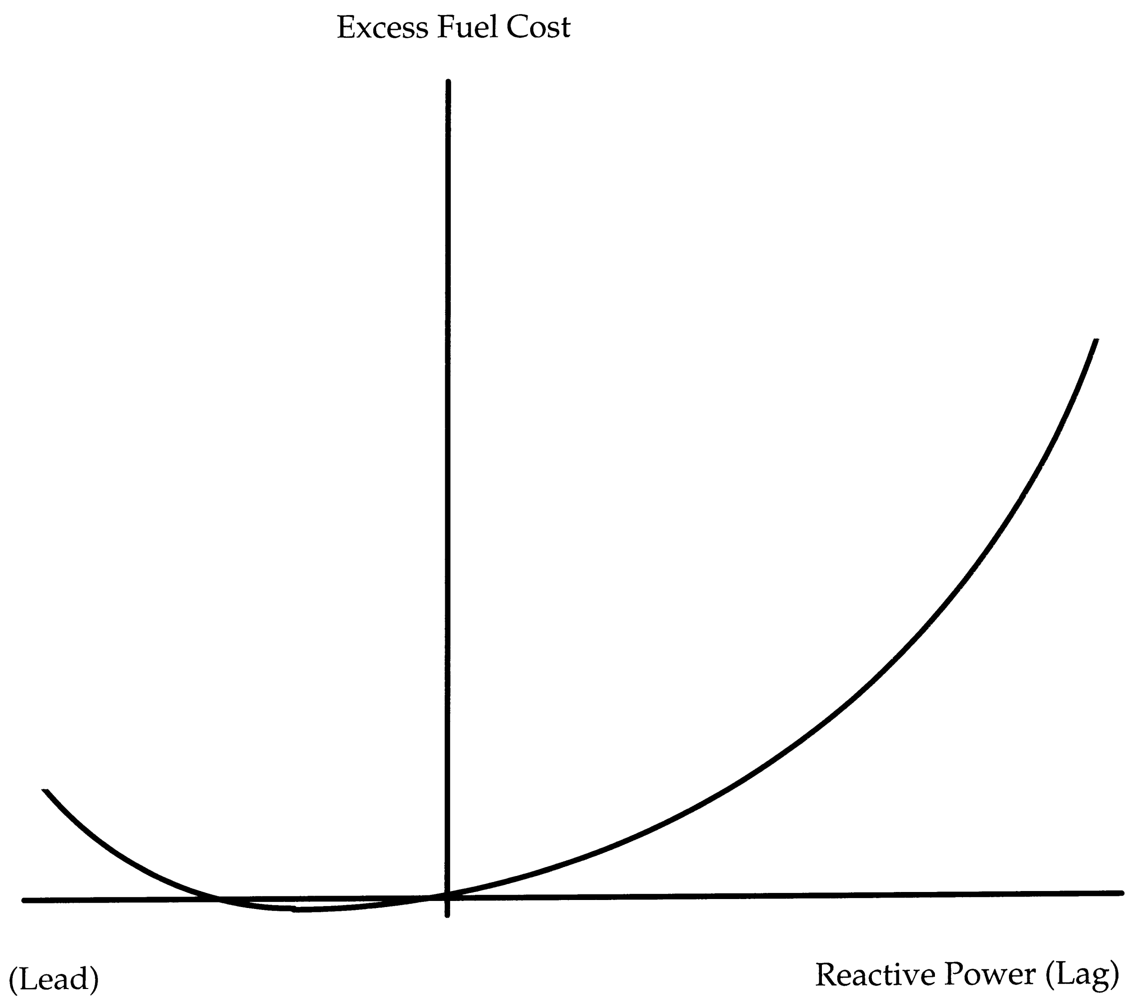

Figure 3-3
Typical graph of Excess Fuel Costs related to VAr production.

The cost of VAr related losses is non-linear due mainly to the I^2 term, but also due to the effect of winding temperature changing resistance and magnetic saturation effects increasing excitation requirements with load and as lagging VAr increases. In some circumstances it may be useful to know the sensitivity of VAr related costs to enable the marginal cost of the last VAr element to be calculated. Differentiation of each cost component equation in an analytic treatment would be unduly complicated and it is suggested that a numerical approach be adopted. Calculation of the incremental cost tends towards the marginal cost as the increment reduces in size. In practical terms the cost of the last MVAr is unlikely to differ significantly from the marginal cost where one MVAr is a small proportion of the machine rating. Such an incremental cost can be found simply by calculating two conditions differing only by one MVAr and subtracting one cost from the other. Some idea of the cost non-linearity and sensitivity of costs to power and VAr can be found from examining the very simplistic assumption that costs of VAr are proportional to the square of phase current. In this case, costs of VAr are proportional to $Q^2/(P^2+Q^2)$ and the marginal price, dC/dQ, is then proportional to $P^2Q/(P^2+Q^2)^2$. It should be expected that the actual numerical calculations will show a stronger nonlinearity but that the general form will be similar to these simple analytic equations.

4

COST OF MAINTENANCE AND REPAIR

Maintenance and repair costs can be related to VAr production on a probabilistic basis by analyzing historical data. Maintenance and repair cost data can be categorized depending on the dominant damage mechanism, averaged and costs indexed to the current year. The historical power and VAr production data can then be analyzed to determine the generation levels for real and reactive power which were responsible for the maintenance and repair costs and thereby produce a logical basis for predicting future costs associated with generating VAr.

When attributing costs to maintenance and repair activities, a choice needs to be made as to whether outage related “lost opportunity” costs are to be included. If such outage related costs are to be included with the actual cost of repair and maintenance, then it must be done fairly and take account of the likelihood that other work, possibly more vital and the real reason for the forced outage, may have been undertaken at the same time. For example, a generator stator gas into coolant leak may occur which cannot be tolerated, causing an unplanned shut-down. While the generator is out of service it might be considered beneficial to bring forward other planned maintenance, unrelated to the original stator fault, causing the outage to be extended slightly. In these circumstances it would be wrong to charge the cost of the all the outage maintenance/repair work, or the whole cost of the lost opportunity for generation, to the original fault which can be related to VAr generation.

4.1 Calculate Maintenance and Repair Costs

The following steps are required to calculate repair and maintenance costs for both the generator and transformer.

1. Sort maintenance and repair costs into groups depending on dominant damage mechanism.

2. Calculate present day average cost per year for each cost group.

3. Allocate VAr related parameters (I_a,I_a^2,I_f^2,T_a&T_f). (Note, the generator stator current, I_a can be considered to be an adequate approximation to generator step-up transformer).

4. Calculate parameter cost per year, per machine as a function of Power and VAr generation levels.

A flow diagram showing the steps in the costing methodology are shown in Figure 1-1.

4.1.1 Sorting Maintenance and Repair Costs into Groups

Materials used in the construction of electrical machines are subject to various ageing mechanisms such as temperature, cyclic stresses, wear and abrasion. Since these phenomena are generally related to the magnitude of the electrical loading applied to the equipment, it is reasonable to suppose that maintenance costs associated with running the machine, and indeed the ultimate service life of the machine, is related to the VAr production.

Any ageing mechanism will be affected by loading or cycling effects. Electrical loading can be broken down into the individual relationships of the voltages and currents applied to the generator, generator transformer and excitation system. Each mechanism can be examined and assigned a relationship to Load Phase Current, I_a, Excitation Current, I_f, Line Voltage, V, Armature Winding Temperature, T_a and Field Winding Temperature, T_f.

In order to assess the affect VAr production may have on the cost of running a particular generating unit, the usual maintenance activities, and possible faults and defects have been broken down into sub groups and assigned a relationship.

To perform the analysis it is necessary to have either a knowledge of the maintenance cost history of the machine concerned, or the history of one or more similar machines. Alternatively it may be acceptable to estimate future costs using best engineering judgment based on typical expectations of service life.

Appendix C contains a more detailed commentary on these groups. It is intended that the Proforma 1, given in Section 9, should be used as a proforma for analyzing maintenance and repair costs. To take account of the maintenance cost of VAr production it is necessary to assign some costs within these proformas. The items listed are intended to be an aid memoir and it is not expected that it will be possible to assign costs to each individual item.

Proforma 1 has been designed to enable a detailed analysis to be carried out. However it is anticipated that in the majority of case studies detailed information on costs will not be available. In the event of detailed data not being available, default values are suggested to enable the analysis to be undertaken in a meaningful way.

Where detailed data on individual machines is scarce, or particular repairs occur infrequently, it would be reasonable to collect data from work done on other machines in the same or similar design family to arrive at notional costs for maintenance and repair of one unit averaged over the family.

Once the cost data has been obtained and sorted into groups, it can be entered on Proforma 1: the information should include, the cost, year of payment and period covered.

4.1.2 Calculate Cost Per Year for each Group

This information is then corrected for inflation and converted to an annual cost using the following expression:

$$\text{Present day cost per year} = \text{Cost}\ (1+i)^n\ /\ \text{period of cost} \qquad \text{(eq. 87)}$$

Where:

n = Number of years from Cost to current year
I = Inflation index rate

Alternatively a set of index tables could be used if index rates have fluctuated significantly during the review period.

4.1.3 Allocate VAr Related Parameters (I_a,I_a^2,I_f^2,T_a&T_f)

Each cost can now be allocated as being proportional to the three main VAr related parameters (I_a,I_a^2,I_f^2) using the spaces provided on the proforma Proforma 1. Clearly some costs will not be related to VAr production and these can be allocated to the "not applicable" n/a column for completeness.

Temperature of field and armature windings, (T_a & T_f) can be taken into account and a method for dealing with this is discussed. However, for a more straightforward analysis, temperatures could be omitted in preference to using just I_f^2 & I_a^2.

4.1.4 Calculate VAr Parameter Cost Per Year

The individual parameter costs can now be summarized on Proforma 1 to give a total cost for each at current price levels. This will give a figure of $/year for each VAr related parameter considered.

4.2 Analyze VAr Production Regime

The cost of maintenance and repair costs due to the VAr related parameters (I_a,I_a^2,I_f^2,T_a&T_f) must be calculated by linking and relating the historical costs to the historical operating regime of the plant. The following steps are required to analyze the VAr production regime:

1. Collect data on historical running regime.

2. Calculate values of parameters (I_a,I_a^2,I_f^2,T_a&T_f) for running regime data.

3. Integrate values of parameters (I_a,I_a^2,I_f^2,T_a&T_f) over time.

4. Calculate additional cost due to VAr production.

4.2.1 Collect Data on Historical Running Regime

The historical repair and maintenance costs must be related to the damage causing parameters (I_a,I_a^2,I_f^2,T_a&T_f) at which the generating unit has operated during the period to which the costs relate. However it is unlikely that (I_a,I_a^2,I_f^2,T_a&T_f) will be available: more readily available parameters will be real power, reactive power and voltage (P, Q & V).

Clearly the most effective method of analyzing the running regime data will utilize some form of computer processing via database or spreadsheet. However a paper method using a simple table could be used to provide a simple analysis of a limited period.

Should this method be adequate, then, for the sake of completeness, Proforma 3 has been provided for this purpose.

4.2.2 Calculate Values of Parameters for Running Regime Data (I_a)

Consider damage proportional to I_a

Now assuming the bus bar voltage is constant. For any output, the apparent power, S, is

$$S = \text{sqrt}\,(\,3\,)\,.\,V\,.\,I_a = \text{sqrt}\,(\,P^2 + Q^2\,) \qquad \text{(eq. 89)}$$

then $$I_a = \text{sqrt}\,(\,P^2 + Q^2\,)\,/\,3\,.\,V \qquad \text{(eq. 90)}$$

Historical operating data in terms of P, Q & V, can be used to calculate I_a

4.2.3 Integrate Values of Parameters (I_a) Over Time

In considering costs due to I_a, we can integrate I_a over the same time as the maintenance and repair costs have been analyzed.

$$\int I_a \, . \, dt \; = \; {}^{n}\Sigma_{i=1} \; \text{sqrt} \; (\, P_i^2 + Q_i^2 \,) \; / \; (\, 3 \, . \, V \, . \, t_i \,) \qquad \text{(eq. 91)}$$

Then by dividing the maintenance and repair cost for I_a related mechanisms by this figure we will get a cost factor, Cf_a, which has the units Dollars/Ampere-second ($/As).

$$Cf_a = \text{Annual } I_a \text{ Related Repair Cost } / \; [\; {}^{n}\Sigma_{i=1} \; \text{sqrt} \; (\, P_i^2 + Q_i^2 \,) \; / \; (\, 3 \, . \, V \, . \, t_i \,) \;] \qquad \text{(eq. 92)}$$

4.2.4 Calculate Additional Cost Due to (I_a) for VAr Production

Using zero VAr generation at the HV terminals as a basis, then, for a given level of Power and VAr production the extra current due to VAr production, I_{aq}, will be given by:

$$I_{aq} = \text{sqrt} \; [\; (\, P^2 + Q^2 \,) \; / \; (\, 3 \, . \, V^2 \,) \;] - \text{sqrt} \; [\; (\, P_{0Q}{}^2 + Q_{0Q}{}^2 \,) \; / \; (\, 3 \, . \, V^2 \,) \;] \qquad \text{(eq. 93)}$$

The cost for I_a related maintenance and repair due to VAr production is now given by the product of I_{aq}, time and the cost factor Cf_a.

$$\text{Cost } (\$) = I_{aq} \, . \, t \, . \, Cf_a \qquad \text{(eq. 84)}$$

In the situation of varying load conditions, the cost can be numerically integrated by summing the cost at individual load points.

4.2.5 Other Damage Causing VAr Parameters

The system for dealing with the other damage causing parameters, I_f^2, I_a^2, T_f, T_a and $T_{t\text{-}HV/LV}$, which apply to the generator and transformer, are similar and essentially repeats sections 4.2.2 to 4.2.4.

4.2.5.1 Calculate The Above for Damage Proportional To (I_a^2)

For the purposes of attributing an underlying damage mechanism, the generator stator current, I_a , can be assumed to be equal to the transformer LV winding current, hence the factor can be related to relevant damage mechanisms in both the generator and transformer.

From the above

$$I_a^2 = (P^2 + Q^2) \; / \; (3 \, . \, V^2) \qquad \text{(eq. 95)}$$

Using the same historical data, in terms of P,Q & V, values of I_a^2 can be calculated and integrated over time.

$$\int I_a^2 \, . \, dt = {}^{n}\Sigma_{i=1} \; (P_i^2 + Q_i^2) \; / \; (3 \, . \, V_i^2 \, . \, t_i) \qquad \text{(eq. 96)}$$

Then by dividing the maintenance and repair cost for I_a^2 related mechanisms by this figure we will get a cost factor, Cf_{a2} , which has the units Dollars/Ampere squared second ($\$/A^2$ s).

$$Cf_{a2} = \text{Annual } I_{a2} \text{ Related Repair Cost } / \; [\; {}^{n}\Sigma_{i=1} \; (P_i^2 + Q_i^2) \; / \; (3 \, . \, V_i^2 \, . \, t_i) \;] \qquad \text{(eq. 97)}$$

For zero VAr operation, the additional I_a^2 component due to VAr generation is given by

$$I_{aq}^2 = [\; (P^2 + Q^2) - (P_{0Q}^2 + Q_{0Q}^2) \;] \; / \; (3 \, . \, V^2) \qquad \text{(eq. 98)}$$

The cost for I_a^2 related maintenance and repair due to VAr production is now given by the product of I_{aq}^2, time and the cost factor Cf_{a2} .

$$\text{Cost } (\$) = I_{aq}^2 \, . \, t \, . \, Cf_{a2} \qquad \text{(eq. 99)}$$

To analyze varying load conditions, costs can be numerically integrated by summing the cost at individual load points.

4.2.5.2 Calculate the Damage Proportional to I_f^2.

If saturation is ignored then E α If and damage proportional to If can simply be calculated form P,Q &V as:

$$I_f \; \alpha \; \text{sqrt} \; [\; P^2 + (V^2 \; / \; X_d + Q)^2 \;] \qquad \text{(eq. 100)}$$

$$I_f^2 \; \alpha \; [\, P^2 + (V^2 / X_d + Q)^2 \,] \qquad \text{(eq. 101)}$$

However, use of this approximate method ignores the effect of magnetic saturation. Provided the data is available it is more appropriate to use the excitation calculation discussed in the loss calculations in section 3.3.2.4 (see equation 68)

Consider costs due to I_f^2 ,we can integrate I_f^2 over time as:

$$\int I_f^2 \,.\, dt = {}^{n}\Sigma_{i=1} \; I_{f\,i}^2 \,.\, t_i \qquad \text{(eq. 102)}$$

Then by dividing the maintenance and repair cost for I_f^2 by this figure we will get another cost factor, Cf_{f2} , which has the units Dollars/Ampere squared second ($/$A^2$ s).

$$Cf_{f2} = \text{Annual } I_{f2} \text{ Related Repair Cost } / \; [.{}^{n}\Sigma_{i=1} \, I_{f\,i}^2 \,.\; t_i \,] \qquad \text{(eq. 103)}$$

When considering the zero VAr condition and the additional I_f component related to VAr generation, then again, if saturation is ignored, E α I_f and damage proportional to I_{fq} can be calculated from P,Q &V directly. Using unity power factor as a basis, for a given level of VAr production, the extra excitation current due to VAr, I_{fq}, will be given by:

$$I_{fq} \, \alpha \; \text{sqrt} \,[\, P^2 + (V^2 / X_d + Q)^2 \,] - \text{sqrt} \,[\, P_{0Q}{}^2 + \; (V^2 \,/\, X_d + Q_{0Q} \,)^2 \,] \qquad \text{(eq. 104)}$$

Note, this is a very simple approach and provided the data is available it is more appropriate to use the excitation calculation discussed in the loss calculations in section 3.3.2.4 (see equation 68).

The cost for I_f^2 related maintenance and repair due to VAr production is now given by the product of $I_{fq}{}^2$, time and the cost factor Cf_{f2}.

$$\text{Cost } (\$) = I_{fq}{}^2 \,.t.\, Cf_{f2} \qquad \text{(eq. 105)}$$

To analyze varying load conditions, the cost can be numerically integrated by summing the cost at individual load points.

4.2.5.3 Calculate the Damage Proportional to Stator Winding Temperature, T_a and Transformer LV winding Temperature $T_{t\text{-}LV}$.

Several of the degradation mechanisms listed in the proformas are a result of stator or transformer winding temperature rather than winding current. Taking the generator stator winding temperature, T_a, first, then combining equations 45 and 48 can give an expression for T_a as

$$T_a = T_{a\text{-in}} + T_{a\text{-rated rise}} \,.\, I_a^2 \,.\, (T_{a\text{-in}} + 391) / [I_{gen\text{-rat}}^2 \,.\, (T_{a\text{-in}} + T_{a\text{-rated rise}} + 391) - T_{a\text{-rated rise}} \,.\, I_a^2] \quad \text{(eq. 106)}$$

Consider costs due to T_a, we can integrate T_a over time.

$$\int T_a \,.\, dt = {}^n\Sigma_{i=1} T_{a\,i} \,.\, t_i \quad \text{(eq. 107)}$$

Then by dividing the maintenance and repair cost for T_a by this figure we will get another cost factor , Cf_{Ta} , which has the units Dollars/°C second (\$/°Cs)

$$Cf_{Ta} = \text{Annual } T_a \text{ Related Repair Cost } / [{}^n\Sigma_{i=1} T_{a\,i} \,.\, t_i] \quad \text{(eq. 108)}$$

Considering the zero VAr condition the additional T_a rise. due to VAr production can simply be calculated form P,Q &V, for a given level of VAr production the increase in temperature, due to VAr production, T_{aq} will be given by:

$$T_{aq} = \{T_{a\text{-rated rise}} \,.\, I_a^2 \,.\, (T_{a\text{-in}} + 391) / [I_{gen\text{-rat}}^2 \,.\, (T_{a\text{-in}} + T_{a\text{-rated rise}} + 391) - T_{a\text{-rated rise}} \,.\, I_a^2]\} - \{T_{a\text{-rated rise}} \,.\, I_{a0Q}^2 \,.\, (T_{a\text{-in}} + 391) / [I_{gen\text{-rat}}^2 \,.\, (T_{a\text{-in}} + T_{a\text{-rated rise}} + 391) - T_{a\text{-rated rise}} \,.\, I_{a0Q}^2]\} \quad \text{(eq. 109)}$$

The cost for T_a related maintenance and repair due to VAr production is now given by the product of T_{aq}, time and the cost factor Cf_{Ta}.

$$\text{Cost (\$)} = T_{aq} \,.\, t \,.\, Cf_{Ta} \quad \text{(eq. 110)}$$

To analyze varying load conditions, the cost can be numerically integrated by summing the cost at individual load points.

Exactly the same logic can be used to get an expression for a cost factor related to transformer winding temperature, $T_{t\text{-LV}}$.

$$T_{t\text{-LV}} = T_{t\text{-in}} + T_{t\text{-LV--rated rise}} \,.\, I_{LV}^2 \,.\, (T_{t\text{-in}} + 391) / [I_{LV\text{-rat}}^2 \,.\, (T_{t\text{-in}} + T_{t\text{-LV-rated rise}} + 391) - T_{t\text{-LV-rated rise}} \,.\, I_{LV}^2] \quad \text{(eq. 111)}$$

Consider costs due to $T_{t\text{-}LV}$, we can integrate $T_{t\text{-}LV}$ over time.

$$\int T_{t\text{-}LV} \,.\, dt = {}^{n}\Sigma_{i=1}\, T_{t\text{-}LV\, i} \,.\, t_i \qquad \text{(eq. 112)}$$

Then by dividing the maintenance and repair cost for $T_{t\text{-}LV}$ by this figure we will get another cost factor , $Cf_{Tt\text{-}LV}$, which has the units Dollars/°C second ($/°Cs)

$$Cf_{Tt\text{-}LV} = \text{Annual } T_{t\text{-}LV} \text{ Related Repair Cost } / \, [\, {}^{n}\Sigma_{i=1}\, T_{t\text{-}LV\, i} \,.\, t_i \,] \qquad \text{(eq. 113)}$$

Considering the zero VAr condition the additional T_a rise. due to VAr production can simply be calculated form P,Q &V, for a given level of VAr production the extra current due to VAr production $T_{t\text{-}LV\text{-}q}$ will be given by:

$$\begin{aligned} T_{t\text{-}LV\text{-}q} = \{ & T_{t\text{-}LV\text{-rated rise}} \,.\, I_{LV}^2 \,.\, (T_{t\text{-}in} + 391) \,/ \\ & [\, I_{LV\text{-}rat}^2 \,.\, (T_{t\text{-}in} + T_{t\text{-}LV\text{-rated rise}} + 391) - T_{t\text{-}LV\text{-rated rise}} \,.\, I_{LV}^2 \,]\} \\ & - \{ T_{t\text{-}LV\text{-rated rise}} \,.\, I_{LV0Q}^2 \,.\, (T_{t\text{-}in} + 391) \,/ \\ & [\, I_{LV\text{-}rat}^2 \,.\, (T_{t\text{-}in} + T_{t\text{-rated rise}} + 391) - T_{t\text{-rated rise}} \,.\, I_{LV0Q}^2 \,]\} \end{aligned} \qquad \text{(eq. 114)}$$

The cost for $T_{t\text{-}LV}$ related maintenance and repair due to VAr production is now given by the product of $T_{t\text{-}LV\text{-}q}$, time and the cost factor $Cf_{Tt\text{-}LV}$.

$$\text{Cost } (\$) = T_{t\text{-}LV\text{-}q} \,.\, t \,.\, Cf_{Tt\text{-}LV} \qquad \text{(eq. 115)}$$

4.2.5.4 Calculate the Damage Proportional to Field Winding Temperature T_f.

Several of the degradation mechanisms listed in the proformas are a result of rotor winding temperature rather than field current. For a more sophisticated analysis it may be appropriate to introduce T_f as a parameter. Using equations 67 and 68 gives an expression for T_f as:

$$\begin{aligned} T_f = T_{f\text{-}in} + \; & T_{f\text{-rated-rise}} \,.\, I_f^2 \,.\, (T_{f\text{-}in} + 391) \,/ \\ & [\, I_{f\text{-}rat}^2 \,.\, (T_{f\text{-}in} + T_{f\text{-rated-rise}} + 391) - I_f^2 \,.\, T_{f\text{-rated-rise}} \,] \end{aligned} \qquad \text{(eq. 116)}$$

Consider costs due to T_f, we can integrate T_f over time.

$$\int T_f \,.\, dt = {}^{n}\Sigma_{i=1}\, T_{f\, i} \,.\, t_i \qquad \text{(eq. 117)}$$

Then by dividing the maintenance and repair cost for T_f by this figure we will get another cost factor which has the units Dollars/°C Second ($/°Cs).

$$Cf_{Tf} = \text{Annual } T_f \text{ Related Repair Cost } / \ {}^{n}\Sigma_{i=1} T_{f\,i} \, . \, t_i \qquad \text{(eq. 118)}$$

Considering the zero VAr condition the additional T_f rise. due to VAr production can simply be calculated form P,Q &V, for a given level of VAr production the extra current due to VAr production T_{fq} will be given by:

$$\begin{aligned} T_{fq} = \{ & T_{f\text{-rated-rise}} \, . \, I_f^2 \, . \, (T_{f\text{-in}} + 391) \ / \\ & [I_{f\text{-rat}}^2 \, . \, (T_{f\text{-in}} + T_{f\text{-rated-rise}} + 391) - I_f^2 \, . \, T_{f\text{-rated-rise}}] \} \\ & - \{ T_{f\text{-rated-rise}} \, . \, I_f^2 \, . \, (T_{f\text{-in}} + 391) \ / \\ & [I_{f\text{-rat}}^2 \, . \, (T_{f\text{-in}} + T_{f\text{-rated-rise}} + 391) - I_f^2 \, . \, T_{f\text{-rated-rise}} \} \end{aligned} \qquad \text{(eq. 119)}$$

The cost for T_f related maintenance and repair due to VAr production is now given by the product of T_{fq}, time and the cost factor Cf_{Tf}.

$$\text{Cost (\$)} = T_{fq} \, . \, t. \, Cf_{Tf} \qquad \text{(eq. 120)}$$

To analyze varying load conditions, costs can be numerically integrated by summing the cost at individual load points.

4.3 Calculate Actual Cost Per VAr

Using the cost factors Cf_a, Cf_{a2}, Cf_{f2}, Cf_{Ta}, Cf_{Tf} and $Cf_{Tt\text{-}LV}$, the values of I_{aq}, $I_{aq}^{\ 2}$, $I_{fq}^{\ 2}$, I_{LV}, T_{aq} & T_{fq} and $T_{t\text{-}LV}$ and equations (94),(99),(105),(110),(115)&(120), it is now possible to calculate the cost of maintenance and repair associated with any level and duration of VAr generation for the generator and Transformer.

5

COST OF PLANT AGEING

5.1 Consideration of Plant Ageing Costs

The effect of VAr production on the life of major components can be significant and some method must be applied to take account of this.

The distinction between what costs should be attributed to plant ageing and what should be categorized as maintenance and repair can be subjective, but does need to be consistent. It would be possible to include the effect of plant ageing as an individual cost and take account of ageing as a purely repair and maintenance spend, as repairs and replacements are carried out. How each cost is categorized is not important provided costs are not included twice or omitted altogether. For example one might consider the rewind of a generator rotor as the equivalent of total replacement and thus should be included as an ageing cost. On the other hand this work could be regarded as a repair to be included as a maintenance and repair cost. However this approach would require maintenance cost data to be gathered over a very long period to ensure that the historical incidence of major equipment replacements was correctly accounted for. The definitions of ageing, repair and maintenance are discussed in section 1 and the definition of ageing as the need to replace or rewind a major component of plant, suggested in section 1.1, is put forward as a practical way of separating more routine expenditures from the least frequent replacement/rewind costs.

A further consideration is whether outage related “lost opportunity” costs are to be included. If they are, such costs must fairly reflect the likelihood of such outages being planned to occur in parallel with other maintenance work: only those costs occurring directly as a result of the decision to replace or rewind electrical plant should be used.

5.2 Consideration of Plant Life

The original design life of a plant may be given as 20 or 25 years. Depending on the operating regime experienced during the life of the plant the actual life may eventually be extended to 40, 45 or even 50 years based on the physical condition of the plant. While the life of the plant may be considerable, the life of individual major components can be much shorter.

It is most unlikely that it will be possible to examine operation of a machine operating entirely at the zero VAr condition and compare it with a machine operated at rated power factor. In fact without the benefit of accurate historical data covering a significant sample of machines it is difficult to predict the precise affect of the VAr generation on the life of components.

There are two approaches to the problem proposed below. The first very simple method uses an estimated notional life for generating units operating at unity and rated power factor. The second more sophisticated approach provides a technique for examining the likely failure modes of individual components and using the damage mechanisms to gain an estimate of the sensitivity of failure rates to the generation of reactive power.

5.3 A Simple Estimation Approach to Plant Ageing Costs

One approach to plant ageing is simply to make an estimate of the life span of the component when operated at the zero VAr condition Y_{0C}, with the same component operated at rated power factor Y_{rat}. It could be estimated that for a typical large generating unit, operating at unity power factor at the HV terminals of the generator transformer, the life of the rotor, stator and transformer might be 20 years each. The affect of operating that same plant items at rated power factor might be to reduce the life of these components to say 12, 17, and 17 years respectively.

The ageing factors affecting the life major components will vary with each individual machine. Mechanical components suffer from wear out mechanisms such as fatigue and creep, insulation materials may suffer from mechanical or chemical breakdown mechanisms.

When considering replacement costs it is necessary to calculate the Net Present Value of a component. New cost estimates can be obtained or alternatively the known values can be corrected for inflation and, an appropriate discount rate can be used.

If the present replacement cost of the component is $C_{r,}$ the inflation index rate, i , and n is the expected number of years to the end of the component life from the present day, then the final replacement cost is

$$\text{Final Cost} = C_r (1 + i)^n \qquad \text{(eq. 121)}$$

and, allowing for the discount rate, D, the net present value, NPV, is

$$NPV = C_r \,.\, [(1 + i)^n \;/\; (1+D)^n] \qquad \text{(eq. 122)}$$

Once the NPV of the component is known a capital recovery factor can be used to calculate an annual rent for the component. To ensure proper returns on investment it is more appropriate to use a compound interest index i_c. In fact two rents need to be calculated, one for the expected component life at the zero VAr condition and the other for the life at rated VAr output. The difference between these two rents will give an annual sum equivalent to the capital sum deployed for the benefit of VAr production.

$$\text{Cost VAr per year} = \text{NPV} \cdot \{ i_c \cdot (1 + i_c)^{Yrat} / [(1 + i_c)^{Yrat} - 1] - i_c \cdot (1 + i_c)^{Y0C} / [(1 + i_c)^{Y0C} - 1] \} \qquad \text{(eq. 123)}$$

where Y_{0C} & Y_{rat} are the component expected life in years at zero VAr and rated power factor respectively.

In calculating this average ageing cost per year, it is necessary to consider the whole life of the component, Yrat and YOC, and not just the expected life from the present day, n. It must be expected that consideration of very short time periods could give unduly unrepresentative results.

5.4 Probabilistic Failure Rate Approach to Plant Ageing

An alternative method to that suggested in 5.3 above centers around the view that the life limiting condition arises when damage has accumulated in some area to a critical level, and, since many damage mechanisms are related to current and temperature, the plant item would have a longer life if its loading was lower, i.e. its life is shortened by VAr production. With knowledge of the plant this concept can be can be refined and further developed. Production of VAr increases electrical loading which can accumulate damage and increase the failure rate. Now by considering the plant in more detail, and focusing on failure rates, it will be possible to give a more detailed assessment of the effect of VAr on plant life.

For this life comparison to have a sound basis, historical failure data needs to be considered. This comparison should be based on the assessment of Maintenance and Repair Costs. Proforma 3 provides a format for the assessment and should be considered when preparing Proforma 1.

As each maintenance and repair item is considered on Proforma 1, an assessment of the life implications can be made and a probability of failure added to Proforma 3. Only failure mechanisms which are likely to lead to the unrecoverable failure of the component should be considered. Failure rates should be considered against the zero VAr generation condition. For example, consider some possible failure modes for a rotor given in Table 3-3.

It should be noted that this is a complex process as some failure modes interact and the addition of new failure mechanisms to the analysis will affect others so a degree of fine tuning may be necessary to achieve sensible results.

Table 5-1
Reliability of Generator Rotor

Failure Mode	Effective VAr Parameter	Failure Rate (Failures/year)	MTBF (years)	Comments
Rotor Winding distortion	I_f^2	0.01	100	Dependent on winding temperature and stop starts. Consider as proportional to field current squared
Forging Cracking	n/a	0.007	143	Can be dependent of heating but not included in VAr related here
Inter-turn Faults	I_f^2	0.015	67	Dependent on field current squared
Cell Insulation Failure	n/a	0.008	125	This could be a dependent on several mechanisms only stop start cycles have been considered here

The availability of the rotor is given by the product of the individual availability's due to each failure mechanism (note: availability's are (1 - Failure Rate)). If λ_1, λ_2, λ_3, to λ_n are individual failure rates, then the overall availability is

$$\text{Availability}_{0Q} = (1 - \lambda_1) . (1 - \lambda_2) . (1 - \lambda_3) .... (1 - \lambda_n) \qquad \text{(eq. 124)}$$

For the above example,

$$\text{Availability}_{0Q} = (1 - 0.01) . (1- 0.007) . (1 - 0.015) . (1 - 0.008)$$
$$= 0.9606$$

and the Mean Time Between Failures at the zero VAr condition, MTBF_{0Q} , is

$$\text{MTBF}_{0Q} = 1/\lambda_{0Q}$$
$$= 1/ (1-0.9606)$$
$$= 25 \text{ years}$$

Now if it is assumed that the failure rate is increased in proportion to the damage mechanism, it is possible to re-assess the failure rates for a new VAr loading.

$$\text{Availability}_{P+Q} = \text{Availability}_{0Q} \,.\, (\text{damage mechanism factor at P+Q}) \;/\; (\text{damage mechanism factor at zero VAr (HV terminals)})$$

$$\text{MTBF}_{P+Q} = 1 / \lambda_{P+Q}$$

For example, if the zero VAr condition required 2.3 p.u. field current and rated VAr output requires 3.6 p.u. field current, then the failure rates will be modified by the factor $(I_{frat}/I_{f0Q})^2$ thus,

$$\begin{aligned}\text{Availability}_{rat} &= (1 - 0.01 \,.\, (3.3 / 2.3)^2) \,.\, (1 - 0.007) \,.\, (1 - 0.015\,(3.3 / 2.3)^2) \,.\\ &\quad (1 - 0.008)\\ &= 0.935\end{aligned}$$

$$\begin{aligned}\text{MTBF}_{rat} &= 1/ (1 - 0.935)\\ &= 15.38 \text{ years}\end{aligned}$$

When calculating the overall life of the rotor care should be taken to adjust individual failure rates to give both a credible life for the component and a meaningful balance between the relative magnitudes of individual failure rates which are consistent with experience.

When considering damage mechanisms associated with armature current squared, failure rates can be similarly treated by the application of the factor $(P^2+Q^2)/(P^2+Q_{0Q}^{\ 2})$ or the equivalent $(PF_{0Q}/PF)^2$

Assuming the assessments have been carried out considering that the plant operates continually, then the load factor needs to be applied to return the above estimates to calendar years rather than accumulated operating time.

Now, as before, it is possible to calculate the annual cost difference between a rotor operating at a given load condition, P+Q, and the zero VAr condition as,

$$\text{Cost VAr per year} = \text{NPV} \,.\, \{ i_c \,.\, (1+ i_c)^{Yp+q} / [(1+ i_c)^{Yp+q} - 1] - i_c \,.\, (1+ i_c)^{Y0C} / [(1+ i_c)^{Y0C} - 1] \} \qquad \text{(eq. 125)}$$

If the compound interest rate, $i_{c,}$ applied is 10% and the present worth is of the plant item is $6m then, for the rated load example given above,

$$\text{Cost VAr per year} = 6x10^{6} \, . \, \{ \; 0.1 \, (1+0.1)^{15} \, / \, [\, (\, 1 + 0.1 \,)^{15} - \,] \, - \; 0.1 \; (\, 1 + 0.1 \,)^{25} \, / \, [\, (1+0.1)^{25} - 1 \,] \, \}$$

$$= \$127{,}830$$

The analysis of relative failure rates and the resultant mean-time-to-failure figure will be checked and refined against operating experience. As a result the figures will inherently be affected by the average load factor, LF. In deriving a cost for MVArhrs, this affect of the load factor need needs to be taken into account, hence, for a given load condition,

$$\text{Cost per MVArhr} = \text{Cost of VAr per year} \; / \; [\text{ hrs/year} \, . \, Q \, . \, LF] \qquad \text{(eq. 126)}$$

The failure rate, λ, used in the analysis above assumes a constant failure rate over the life of the equipment. Given the frequently random nature of plant problems, this approach may not be invalid but, should adequate data be available, analysis could be improved by use of a technique which more accurately models some acceleration in failure rates which might reasonably be expected to apply to these components towards the end of their operating life.

It is inevitable that at some stage the question will be raised that all components should be capable of their continuous maximum design rating for the duration of the design life. Even if this is the case, each component will undoubtedly last longer if the operating regime for VArs was less arduous. Since the technique described only requires a comparison to be made between two distinct operating regimes it is unaffected by the original design life.

6

DISCUSSION

The methodology presented which calculates the cost of generating reactive power from generating plant, accounts for the additional energy losses and the costs associated with maintenance, repairs and plant ageing. The methodology can also include the costs associated with "lost generation opportunity" due to the likely incidence of forced outages. This can be achieved by incorporating these costs into the analysis of historical maintenance, repair and ageing costs since these are used to derive the cost factors which enable the cost component due to VAr generation to be extracted. Not included in this methodology are the costs associated with the extra capital costs of plant and the cost of managing the risks to plant generating VAr and closer to their maximum rating.

Calculation of the losses can be fairly accurate if a reasonable set of electrical plant data is available. There is little point in attempting to measure VAr related losses unless generated output can be resolved to less than 0.1% of full load and output can be maintained stable within 0.1% limits over the time it takes to swing VAr generation levels and measure the change in generated output. Not only is this almost certainly impractical, but even with 0.1% accuracy, the VAr related losses would still only be measured to an accuracy of about +/- 20%. Since the generator and transformer will have been originally purchased with guarantees of efficiency, there must exist sufficient information to calculate the loss components fairly accurately and significantly better than any in-situ power station test. However, it should be recognized that plant upgrades and rewinds can change the original parameters.

Costs are normally calculated from the basis of the additional fuel which is required. However, in some circumstances, it may be justified to use the market value of the VAr related electrical energy losses if it can be shown that this energy could have been sold without any counterbalancing income reduction due to less energy being generated elsewhere by the utility's plant.

The unity power-factor base, from which the additional losses when generating VArs are calculated, is taken to be at the generator transformer step-up transformer HV terminals, since this is usually the interface between the generating station and the system. This requirement complicates the analysis since it requires the generator operating conditions to be derived for both the desired load and the unity power-factor conditions. In addition to this, the extra losses associated with generator excitation increase most rapidly, due, in part, to the effect of magnetic saturation within the machine, and this also complicates the method. While it is possible to simplify the method to get a very rough approximation by simply assuming that electrical losses are approximately proportional to $Q^2/(P^2+Q^2)$, this would significantly underestimate the losses. It is envisaged that this more complicated method presented in this report can be incorporated into a software spreadsheet application: only the application of the method to case studies will tell what is the best way to do it.

The cost of VAr related energy losses, which this methodology calculates, is the variable cost: that is the total additional cost associated with generating at a particular level of VAr. Clearly this cost is very non-linear, being relatively small at low levels of VAr but increasing very approximately proportional to VAr^n , where n is > 2 , due to the combined effect of the current squared terms, the effect of winding temperatures increasing resistance and the fact that rotor excitation increases more rapidly than a simple proportional to VAr rule would suggest. For instance the loss per MVAr in a generator operating at full load, 300MVAr would typically be over twice the value of the loss per MVAr for the same generator operating at 100MVAr and this change is reflected in the change of marginal losses which increase with increasing lagging MVAr.

While there can be no doubt that the generation of VArs increases losses, there is some scope for debate in deciding how additional costs associated with maintenance, repair and plant ageing can be treated. It could be argued that the plant must be designed for its rating, with VAr production forming an integral part of any functional specification. However experience has shown that electrical plant is subject to various wearout and ageing mechanisms most of which are related to electrical loading in some way. The methodology developed here identifies those items of expenditure on maintenance, repair or plant ageing, which can be related to load dependent damage mechanisms and then attributes a fair portion of these costs to VArs.

The key to accurately assessing costs is good data; data on the historic incidence of maintenance, repairs and major plant component replacements, the associated costs and the primary engineering cause of each problem. In addition to this is the need to relate these historical costs to the historical operating regime; the number of cumulated operating hours at different typical loads and power-factors. Such data will often be difficult to obtain. This will not prevent the method from working since it would be possible to use predictive (budgetary) costs and generation levels as a basis for the analysis; only accuracy and confidence is likely to suffer.

Costs are allocated on the basis of the forcing function causing the damage mechanism rather than the damage mechanism directly. For example, problems due to loosening of stator endwinding supports is assumed to be proportional to I^2 since conductor forces are proportional to I^2. It is possible that the loosening mechanism is non-linear, i.e. very little loosening occurring at low levels but loosening starting to occur above a certain threshold. Without very detailed engineering analysis into individual problems this aspect cannot possibly be taken into account. However, in many cases any non-linearity is likely to amplify the effect of the forcing function, so the assumption of a linear relationship would tend to reduce the VAr related cost estimates below that which might really be occurring.

7

CONCLUSIONS

Use of generating plant to provide reactive power to support system voltage levels has a number of cost implications. This report describes a methodology to calculate the cost of additional electrical losses and to estimate the component of maintenance, repair and plant ageing costs associated with generating reactive power. The basis for these costs is the additional losses and damage that occurs when generating reactive power, compared to the condition when there is zero reactive power but the same real power being generated at the HV terminals of the step-up transformer. While there is scope for the methods used to be simplified, it is envisaged that the methodology could be developed into a spreadsheet application.

Electrical losses associated with reactive power are almost completely associated with the generator and step-up transformer. The method developed calculates the affect VAr generation has on each of these loss components and discounts the possibility of testing methods due to the difficulty of measuring small changes in losses within much larger power generation levels.

In the analysis of costs associated with maintenance and repairs, the proportion of the costs associated with reactive power generation is determined by analyzing the historical incidence of costs and determining whether the cost is associated with a VAr related damage mechanism such as stator current loading. Outage related “lost opportunity” costs can also be included in this analysis. Costs related to plant ageing are separated and based on the likely affect VAr generation has on the expected life of the component and the annual notional charges which are required to “pay” for a future replacement.

Although the approximate breakdown of generator losses, given in Table 3-1, applies to typical cylindrical turbine generators, the methodology for costing reactive power is equally applicable to salient pole hydro or diesel-driven generators.

8

REFERENCES

1. IEC 34-2 (1972) Pt. 2. “Methods for Determining Losses and Efficiency of Rotating Electrical Machinery from Tests”.

2. Fenton and Gott, CIGRÉ Working Group WG 11.01, “Ageing of Machines with Respect to Load off Field Current Cycling”. ÉLECTRA No. 163 December 1995.

3. IEEE Std. 1110-1991. “IEEE Guide for Synchronous Generator Modeling Practices in Stability Analyses”

9

PROFORMAS

9.1 Proforma 1

(See following sheets)

Proforma 1

Allocation of Maintenance and Repair Costs

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Item No	Condition	Problem	Mechanism	Operator Allocation	Actual Cost	Date of Cost	Period of Cost	Annual NPV	Allocated Costs/year							
					$	Date	Months	$/year	I_a	I_a^2	I_f	I_f^2	T_a	T_f	T_{t_lv}	T_{t_hv}
	Generator Stators															
1.1	Stator inspection	Frequency of Inspection Required	The frequency of inspection is generally related to the need to examine stator wedge tightness	I_a^2,T_a												
1.2	Stator Winding	General		I_a^2,T_a												
1.2.1	Sub conductor cracking	Generally causes gas into coolant leaks	Driven by Vibration	I_a^2,T_a												
1.2.2	Slot wedge slackness and fretting	Slot wedge slackness	Driven by Vibration	I_a^2												
1.2.3	Insulation failure	Worming	Magnetic	I_a												
1.2.4	Insulation failure	Abrasion (slots)	Effect of slot wedge slackness	I_a^2												
1.2.5	Insulation failure	Switching and Lightening Surges	Not VAr related	N/A												
1.2.6	Other Stator Winding Problems			I_a^2,T_a												
1.3	General Stator Endwinding Problems			I_a^2												
1.3.1	End winding slackness and fretting	End winding slackness	Can be due to core ovalising but mainly conductor vibration driven	I_a^2												
1.3.2	Endwinding Insulation Abrasion	Insulation Abrasion (Endwindings)	Generally current induced vibration	I_a^2												
1.3.3	Other Endwinding Problems			I_a^2												
1.4	General Core Problems															

Proforma 1

Allocation of Maintenance and Repair Costs

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Item No	Condition	Problem	Mechanism	Operator Allocation	Actual Cost	Date of Cost	Period of Cost	Annual NPV	Allocated Costs/year							
					$	Date	Months	$/year	I_a	I_a^2	I_f	I_f^2	T_a	T_f	T_{t_lv}	T_{t_hv}
1.4.1	Core end heating damage		Leading var, but also axial forces and pole slip incidents	I_a												
1.4.2	Core Damage		related to ovalising forces which can vary with load. (Assumed to be constant)	N/A												
1.4.3	Other Core Problems															
	Generator Rotors															
2.1	Rotor Inspections	Frequency of Inspection Required	The frequency of inspection is generally related to the need to examine stator wedge tightness unless known rotor problems exist	I_f												
2.2	Rotor Vibration	General Rotor Vibration see below for specific causes		I_f^2												
2.2.1	Rotor Vibration	Displaced Endrings	Thermally induced	I_f^2												
2.2.2	Rotor Vibration	Displaced packing blocks	Thermally induced	I_f^2												
2.2.3	Rotor Vibration	Stick/slip problems	Thermally induced	I_f^2												
2.2.4	Rotor Vibration	Inter-turn heating	Thermally induced	I_f^2												
2.2.5	Rotor Vibration	Asymmetric ventilation	Thermally induced	I_f^2												
2.3	General Rotor Winding Problems			I_f^2												
2.2.4	Rotor Vibration	Inter-turn heating	Thermally induced	I_f^2												
2.2.5	Rotor Vibration	Asymmetric ventilation	Thermally induced	I_f^2												
2.3	General Rotor Winding Problems															
2.3.1	Rotor Earth Faults	Contamination	Not usually var related	N/A												

Proforma 1

Allocation of Maintenance and Repair Costs

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Item No	Condition	Problem	Mechanism	Operator Allocation	Actual Cost	Date of Cost	Period of Cost	Annual NPV	Allocated Costs/year							
					$	Date	Months	$/year	I_a	I_a^2	I_f	I_f^2	T_a	T_f	T_{t_lv}	T_{t_hv}
2.3.2	Rotor Earth Faults	Cracked liners	Not usually var related	N/A												
2.3.3	Rotor Earth Faults	Inter-turn fault overheating	Thermally induced	I_f^2												
2.3.4	Rotor Earth Faults	Broken cross-overs	Not usually var related	N/A												
2.3.5	Rotor Earth Faults	Radial stalk failures	Not usually var related	N/A												
2.3.6	Rotor Earth Faults	Hot spot overheating	Thermally induced	I_f^2												
2.3.7	Inter-turn fault	Contamination	Not usually var related	N/A												
2.3.8	inter-turn fault	Insulation or Copper Movement	Thermally induced	I_f^2												
2.3.9	inter-turn fault	Hotspot overheating	Thermally induced	I_f^2												
2.3.10	inter-turn fault	Over voltage breakdown	Pole slip induced, stability issue													
2.3.11	Other Rotor Winding Problems															
2.4	General Rotor Mechanical Problems															
2.4.1	Forging Defect	Forging Cracks	not usually var related but some links with temperature are possible	N/A												
2.4.2	Other Rotor Mechanical Problems															
2.5	Slipring Replacement		related to excitation current	I_f^2												
2.5.1	Slipring Machining		related to excitation current	I_f^2												
2.5.2	Brushgear Maintenance	Brush replacement	related to excitation current	I_f^2												

Proforma 1

Allocation of Maintenance and Repair Costs

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Item No	Condition	Problem	Mechanism	Operator Allocation	Actual Cost	Date of Cost	Period of Cost	Annual NPV	Allocated Costs/year							
					$	Date	Months	$/year	I_a	I_a^2	I_f	I_f^2	T_a	T_f	T_{t_lv}	T_{t_hv}
	Excitation Systems															
3.1	Excitation System Problems			I_f^2												
3.2	AVR Problems			I_f^2												
3.3	Field Breaker Problems			I_f^2												
	Transformers															
4.1	Transformer Inspections	Frequency of Inspection Required	Generally only carried out following problems. Therefore related to the cause of the inspection which may be var related													
4.1.1	Transformer gas in oil testing	Frequency of Inspection Required	The need for testing is related to heat ageing and mechanical vibration induced ageing of insulation materials, both are proportional to Ia2	I_a^2, T_{t_lv}, T_{t_lv}												
4.1.2	Tap-changer inspections		All tapchanger costs are var related since the equipment has no other purpose	I_a^2												
4.1.3	Tapchanger repairs and maintenance	All tapchanger problem	All tapchanger costs are var related since the equipment has no other purpose	I_a^2												
4.1.4	Other Transformer Problems			I_a^2, T_{t_lv}, T_{t_lv}												
								Totals	I_a	I_a^2	I_f	I_f^2	T_a	T_f	T_{t_lv}	T_{t_hv}

9.2 Proforma 2

(See following sheets)

Proformer 2

Analysis of VAr Production Regime

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Date	Time	Durat-ion	Output Data				Calculated Parameters								Integrated Parameters										
		hours	P, MW	Q, MVAr	V, Volts	Tap	I_a	I_a^2	I_f	I_f^2	T_a	T_f	T_{t_lv}	T_{t_hv}	MWh	MVArh lead	MVArh lag	I_a	I_a^2	I_f	I_f^2	T_a	T_f	T_{t_lv}	T_{t_hv}
Totals													Totals												

9.3 Proforma 3

(See following sheets)

Proforma 3

Allocation of Ageing Failure Rates

Generator Stator

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Item No	Condition	Problem	Failure Mode	Operator Allocation	Avail-ability	Failure Rate	MTBF	Comments	Effective VAr Parameter								
						n/Yr	Yrs		n/a	I_a	I_a^2	I_f	I_f^2	T_a	T_f	Total	MTBF
								Total Availability									
								Basic Failure Rate									
								Adjusted Failure Rate									

Stator Cost		Compound Interest Rate	
Current Year		Load Factor	

Proforma 3

Allocation of Ageing Failure Rates

Generator Stator

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Item No	Condition	Problem	Failure Mode	Operator Allocation	Avail-ability	Failure Rate	MTBF	Comments	Effective VAr Parameter								
						n/Yr	Yrs		n/a	I_a	I_a^2	I_f	I_f^2	T_a	T_f	Total	MTBF
								Total Availability									
	Stator Cost		Compound Interest Rate					Basic Failure Rate									
	Current Year		Load Factor					Adjusted Failure Rate									

Proforma 3

Allocation of Ageing Failure Rates

Generator Stator

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Item No	Condition	Problem	Failure Mode	Operator Allocation	Avail-ability	Failure Rate	MTBF	Comments	Effective VAr Parameter								
						n/Yr	Yrs		n/a	I_a	I_a^2	I_f	I_f^2	T_a	T_f	Total	MTBF
								Total Availability									
								Basic Failure Rate									
								Adjusted Failure Rate									

Stator Cost		Compound Interest Rate	
Current Year		Load Factor	

Proforma 3

Allocation of Ageing Failure Rates

Generator Stator

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Item No	Condition	Problem	Failure Mode	Operator Allocation	Avail-ability	Failure Rate	MTBF	Comments	Effective VAr Parameter								
						n/Yr	Yrs		n/a	I_a	I_a^2	I_f	I_f^2	T_a	T_f	Total	MTBF
								Total Availability									
								Basic Failure Rate									
								Adjusted Failure Rate									

Stator Cost		Compound Interest Rate	
Current Year		Load Factor	

A

LIST OF SYMBOLS

General Labels

Symbol	Description	Units
A	coefficient	(A/V)
Area	cross-sectional area	(m^2)
B	coefficient	(A/V^n)
C	Cost	($)
Cf	Cost factor	($/As, or $\$/A^2s$ or $/°Fs)
D	Discount rate	(%)
E	Induced/internal Voltage	(V)
F	Fractional value	
I	Current	(A)
i	Inflation rate	(%)
K	Correction Factor	
L	Power Loss	(W)
LF	Load Factor	(p.u.)
Lgth	Length of conductor	(m)
MTBF	Mean time to failure	(years)
MVA	Volt Amp rating ($\div 10^6$)	(MVA)
n	number	
N	Number of turns	
NPV	Net present value	($)
P	Power	(W)
PF	Power Factor	
PU	Per-Unit (part) Load	(p.u.)
Q	Reactive Power	(VAr)
R	Resistance	(Ω)
t	tapping step or time	(s)
T	Temperature	(°F)
V	Voltage (line voltage in 3-ph systems unless otherwise specified)	(V)
VA	Volt-Amps	(VA)
X	Reactance	(jΩ) *
Y	Equipment life	(years)

ϕ	power factor angle	(radians)
η	efficiency	(%)
ρ	resistivity	(Ωm)
λ	component failure rate per operating year	(failures/year)

* note: subscript may denote per-unit quantity.

Sub-Script Notation

a	generator armature (stator)
ac	alternating current value (of resistance)
actual	actual value (at some general condition)
ag	air-gap line quantity
aq	additional armature (stator) component related to VAr (current or temperature)
a2	component related to armature (stator) current squared
aux	auxiliary power flow via unit transformer
c	compound interest rate
calc	calculated quantity
copper	transformer "copper" variable load
core	transformer core value
cycle	thermodynamic cycle value
d	d-axis of generator
dc	d.c. value (of resistance)
e	exciter
ex	exciter
f	generator field
f2	component related to field current squared
fq	additional field component related to VAr (current or temperature)
fx	Fixed/Constant component
fuel	fuel quantity
gen	generator quantity (at LV side of generator transformer)
HV	HV side of generator step-up transformer
i	iron (losses)
I	I th contribution of summation
in	coolant inlet condition
int	internal voltage
I2R	Resistive I^2R loss
LV	LV side of generator step-up transformer
l	leakage (reactance)
low	low value
max	maximum value
misc	miscellaneous value
known	known value
n	number of years or
n	max number of contributions in summation
nom	nominal value

norm	normal value
oc	rated voltage open-circuit condition
out	Output quantity (at HV side of generator transformer)
p	Potier reactance
pu	Per-Unit quantity
p+q	general load condition (Power and VAr)
q	q-axis of generator
q	quantity related to VAr generation
r	replacement (cost)
rat	at the rated load condition
rated	at the rated load condition
reduced	reduced (gas pressure) value
rem	remaining quantity
rise	temperature rise quantity
rpf	Rated power factor
s	stray (losses)
step	step (of transformer tapping)
sat	saturated value
stray	stray losses
T	at specified temperature T
Ta	component due to temperature of armature (stator) winding
Tf	component due to temperature of field winding
t	transformer
tap	transformer tapping position away from nominal
t-rated	total value at rated load
thermal	thermodynamic quantity
total	total value
total-rated	total value at rated load
turb	turbine quantity
uncorrected	uncorrected quantity
upf	Unity power factor
variable	variable component (of losses)
w	friction and windage
y	life in years
0Q	quantity corresponding to the zero VAr condition
1	Positive sequence value
68	at 68 deg.F
@68deg	at 68 deg.F
167	at 167 deg.F
1,2,3...	load conditions 1,2,3 etc.

B

DATA REQUIREMENTS

Required Input Data

C_{fuel}	cost of fuel	(\$/MJ)
C_r	replacement costs of major components	(\$)
D	discount rate used in financial calculations	(p.u.)
$I_{f\text{-}oc}$	rotor excitation current at rated voltage, open-circuit	(A rms)
$I_{f\text{-}rat}$	rotor excitation at rated load	(A)
i	inflation rate	(p.u.)
i_c	compound interest rate	(p.u.)
LF	load factor (historical or typical)	(p.u.)
$MVA_{t\text{-}rat}$	transformer rated MVA	(MVA)
$P_{gen\text{-}rat}$	rated generator power	(W)
$PF_{gen\text{-}rat}$	generator rated power factor	
$V_{gen\text{-}rat}$	rated generator line voltage	(V rms)
$V_{t\text{-}LV\text{-}rat}$	rated transformer line voltage on LV	(V rms)
$V_{t\text{-}HV\text{-}rat}$	rated transformer line voltage on HV	(V rms)
Xd_{pu}	per-unit d-axis synchronous reactance of generator	(p.u.)
$Xd_{pu}^{/}$	per-unit d-axis sub-transient reactance of generator	(p.u.)
Xq_{pu}	per-unit q-axis synchronous reactance of generator (salient pole)	(p.u.)
$X_{t\text{-}nom\text{-}pu}$	transformer leakage reactance on nominal tap	(p.u.)
$\eta_{gen\text{-}rat}$	generator efficiency at rated load	(%)
$\eta_{t\text{-}rat}$	transformer efficiency at rated load	(%)
$\eta_{thermal}(P)$	thermal efficiency of plant (not inc. electrical equipment) at output P	(%)

Desired Input Data

$I_f(1)$	generator field excitation on air-gap line at line voltage V(1)	(A)
$I_f(2)$	generator field excitation at line voltage V(2), $I_f(2) = I_{f\text{-}oc}$	(A)
$I_f(3)$	generator field excitation from OC curve at line voltage V(3)	(A)
$L_{a\text{-}gen\text{-}rat}$	generator stator I^2R loss at rated load	(W)
$L_{e\text{-}gen\text{-}rat}$	generator exciter loss at rated load	(W)
$L_{f\text{-}gen\text{-}rat}$	generator rotor I^2R loss at rated load	(W)
$L_{i\text{-}gen\text{-}rat}$	generator stator core loss at rated load	(W)
$L_{s\text{-}gen\text{-}rat}$	generator stray load loss at rated load	(W)
$L_{t\text{-}core\text{-}rat}$	transformer core losses at rated load	(W)

$L_{w-gen-rat}$	generator friction and windage loss at rated load	(W)
$P_{aux-max}$	unit auxiliary power at maximum rated load	(W)
$P_{aux-low}$	unit auxiliary power at a low generated load	(W)
$P_{gen-low}$	generated load at the condition assumed for the $P_{aux-low}$ value	(W)
$PF_{aux-max}$	power factor of the auxiliary unit load	
PU_t	transformer per-unit load condition for which h_t is known	(p.u.)
R_{a-dc}	generator stator phase resistance at specified temperature, T_a	(Ohms)
R_f	generator rotor field winding resistance at specified temperature, T_f	(Ohms)
R_{t-LV}	resistance of transformer LV phase at temperature T_{t-LV}	(Ohms)
R_{t-HV}	resistance of transformer HV phase at temperature T_{t-HV}	(Ohms)
R1	positive sequence resistance of generator stator phase	(Ohms)
T_a	temperature of generator stator appropriate to Ra_{dc}	(°F)
T_{a-in}	stator winding coolant inlet temperature	(°F)
$T_{a-rated-rise}$	stator winding temperature rise at rated load	(°F)
T_f	temperature of generator rotor field appropriate to R_f	(°F)
T_{f-in}	rotor winding coolant inlet temperature	(°F)
$T_{f-rated-rise}$	rotor winding temperature rise at rated load	(°F)
T_{t-in}	transformer coolant inlet temperature	(°F)
T_{t-LV}	temperature of transformer LV winding appropriate to R_{t-LV}	(°F)
T_{t-HV}	temperature of transformer HV winding appropriate to R_{t-HV}	(°F)
$T_{t-LV-rated-rise}$	transformer LV winding temperature rise at rated load	(°F)
$T_{t-HV-rated-rise}$	transformer HV winding temperature rise at rated load	(°F)
t_{step}	fractional tapping step of generator transformer	
V(1)	generator line voltage approx. rated volts corresponding to $I_f(1)$	(V rms)
V(2)	generator line voltage approx. rated volts corresponding to $I_f(2)$	(V rms)
V(3)	generator line voltage at 1.2 to 1.3 p.u. volts corresponding to $I_f(3)$	(V rms)
V_{f-rat}	rotor excitation voltage at rated load	(Volts)
η_t	transformer part-load efficiency	(%)
λ	failure rates due to different plant problems (incidents/year)	

Assumed Data (default data used in absence of desired input data)

F_a	generator stator I^2R losses as a fraction of the total at rated load	
F_e	generator exciter losses as a fraction of the total at rated load	
F_{e-fx}	fraction of total exciter rated load losses which are fixed	
F_f	generator rotor I^2R losses as a fraction of the total at rated load	
F_i	generator stator iron losses as a fraction of the total at rated load	
F_s	generator stray load losses as a fraction of the total at rated load	
F_w	generator stator I^2R losses as a fraction of the total at rated load	
η_{ex-rat}	exciter efficiency at rated load	(%)

Variable Input Data

n	transformer tap number. n +ve increases turns ratio of transformer	
$P_{HV\text{-}out}$	power output on HV side of generator transformer	(W)
$Q_{HV\text{-}out}$	reactive power output on HV side of generator transformer	(VArs)
$V_{pu\text{-}HV\text{-}out}$	per unit voltage on HV side of generator transformer	(p.u.)

Calculated Data

A	coefficient for generator OC characteristic (air-gap line gradient)	(A/V)
B	coefficient for generator OC characteristic (saturation constant)	($/V^n$)
Cf_a	factor for costs related to I_a	($/As)
Cf_{a2}	factor for costs related to I_a^2	($/As)
Cf_f	factor for costs related to I_f	($/As)
Cf_{f2}	factor for costs related to I_f^2	($/As)
Cf_{Ta}	factor for costs related to stator winding temperature	($/°F)
Cf_{Tf}	factor for costs related to rotor winding temperature	($/°F)
E_f	generator field excitation induced internal voltage	(V)
Id	d-axis component of generator current	(A)
Iq	q-axis component of generator current	(A)
I_{aq}	additional stator current component due to VAr	(A)
$I_{aux\text{-}real}$	real component of auxiliary current drawn from LV busbar	(A)
$I_{aux\text{-}imag}$	imaginary component of auxiliary current drawn from LV busbar	(A)
I_f	generator field excitation	(A)
$I_{f\text{-}sat}$	field excitation component due to magnetic saturation	(A)
$I_{f\text{-}uncorrected}$	calculated but uncorrected field excitation component	(A)
I_{gen}	generator stator terminal current	(A)
$I_{gen\text{-}0Q}$	generator stator terminal current at zero VAr condition	(A)
$I_{gen\text{-}rat}$	generator stator rated current	(A)
$I_{HV\text{-}rat}$	rated phase current at HV terminals of step-up transformer	(Amps)
I_{HV}	phase current at HV terminals of step-up transformer	(Amps)
$I_{t\text{-}LV}$	phase current at LV terminals of the generator step-up transformer	(Amps)
I_{LV}	phase current at LV terminals of the generator step-up transformer	(Amps)
$I_{LV\text{-}0Q}$	phase current at LV terminals of the transformer at zero VAr condition	(Amps)
K_{sat}	saturation correction factor applied to field excitation calculation	
$K_{sat\text{-}max}$	maximum saturation correction factor applied for rated load condition	
$L_{gen\text{-}rat}$	total generator losses at rated load	(W)
L_a	generator stator I^2R loss at specified load	(W)
$L_{a\text{-}q}$	generator stator VAr related I^2R loss at specified load	(W)
L_e	generator exciter loss at specified load	(W)
$L_{e\text{-}q}$	generator exciter VAr related loss at specified load	(W)
L_f	generator rotor I^2R loss at specified load	(W)
$L_{f\text{-}q}$	generator rotor I^2R VAr related loss at specified load	(W)

L_i	generator stator core loss at specified load	(W)
L_{i-q}	generator stator core VAr related loss at specified load	(W)
L_{known}	total of generator losses calculated from known parameters	(W)
L_{misc}	miscellaneous other losses (such as busbar)	(W)
$L_{misc-rat}$	miscellaneous other losses at rated load	(W)
L_{rem}	remaining losses in generator after L_{known} extracted from rated losses	(W)
L_s	generator stray load loss at specified load	(W)
L_{s-q}	generator stray load VAr related loss at specified load	(W)
L_{t-core}	transformer core losses at a specific load	(W)
$L_{t-core-q}$	transformer core losses related to VAr	(W)
$L_{t-copper}$	transformer copper (variable) losses at a specific load	(W)
$L_{t-copper-rat}$	transformer copper (variable) losses at rated load	(W)
$L_{t-HV-I2R}$	transformer HV I^2R loss at specified load	(W)
$L_{t-HV-I2R-q}$	transformer HV I^2R loss related to VAr	(W)
$L_{t-LV-I2r}$	transformer LV I^2R at specified load	(W)
$L_{t-LV-I2r-q}$	transformer LV I^2R loss related to VAr	(W)
$L_{t-misc-q}$	miscellaneous loss (bus bar) related to VAr	(W)
$L_{t-stray}$	transformer stray loss at specified load	(W)
$L_{t-stray-q}$	transformer stray loss related to VAr	(W)
$L_{t-total-q}$	transformer total loss related to VAr	(W)
$L_{t-total-rat}$	transformer total losses at rated load (core + copper)	(W)
L_{w-q}	generator friction and windage losses attributable to VAr	(W)
$N_{t-actual}$	turns ratio of step-up transformer at tapping n_{tap}	
N_{t-nom}	generator transformer nominal turns ratio	
NPV	net present value	($)
n	coefficient for generator OC characteristic (saturation power)	
P_{aux}	total auxiliary power taken from LV busbar	(W)
P_{gen}	total power output at generator terminals	(W)
P_{gen-0Q}	total power output at generator terminals at zero VAr condition	(W)
PF_{gen}	power factor at generator terminals	
PF_{gen-0Q}	power factor at generator terminals for zero VAr condition at HV	
Q_{aux}	total auxiliary reactive power taken from LV busbar	(VAr)
Q_{gen}	total reactive power output at generator terminals	(VAr))
Q_{gen-0Q}	total reactive power output at generator terminals for zero VAr at HV	(VAr)
$R_{a-dc@68deg}$	dc resistance of generator stator phase at 68 deg.F	(Ohms)
R_{a-t}	dc resistance of generator stator phase at operating temperature	(Ohms)
R_{dc-167}	effective dc resistance of busbar at 167 deg.F	(Ohms)
R_{f-68}	field winding resistance at 68 deg.F	(Ohms)
$R_{t-HV-rat}$	resistance of transformer HV phase at rated load	(Ohms)
R_{t-LV-T}	phase resistance of transformer LV winding at working temperature	(Ohms)
R_{t-nom}	nominal effective phase resistance of transformer to account for losses	(Ohms)

T_a	operating temperature of generator stator winding	(°F)
T_{aq}	additional stator winding temperature rise due to VAr generation	(°F)
T_f	rotor winding temperature	(°F)
T_{fq}	additional rotor winding temperature rise due to VAr generation	(°F)
$T_{t\text{-}LV\text{-}rise}$	transformer LV winding temperature rise	(°F)
V_{gen}	generator and transformer terminal line voltage	(V)
$V_{gen\text{-}0Q}$	generator and transformer terminal line voltage at zero VAr condition	(V)
V_{int}	internal voltage within generator representing behind Potier reactance	(V)
$V_{t\text{-}LV}$	transformer internal voltage on LV side of ideal transformer	(V)
$V_{t\text{-}LV\text{-}0Q}$	transformer internal voltage at zero VAr condition	(V)
V_{HV}	terminal line voltage at transformer HV terminals	(V)
$V_{HV\text{-}0Q}$	terminal line voltage at transformer HV terminals for zero VAr	(V)
Xq	q-axis synchronous reactance of cylindrical rotor generator	jOhms)
Xp	Potier reactance of generator	(jOhms)
Xp_{pu}	Potier reactance of generator	(p.u.)
ϕ_{gen}	power factor angle between voltage and current at generator terminals	(radians)
$\phi_{gen\text{-}0Q}$	power factor angle at generator terminals for zero VAr condition	(radians)
ϕ_{HV}	power factor angle between voltage and current at HV terminals	(radians)
$\phi_{HV\text{-}0Q}$	power factor angle at HV terminals for zero VAr condition	(radians)
ϕ_{LV}	power factor angle at LV terminals of the transformer	(radians)
$\phi_{LV\text{-}0Q}$	power factor angle at LV terminals at zero VAr condition	(radians)
η_{cycle}	thermodynamic cycle efficiency	(fractional)
$\eta_{thermal}$	thermal efficiency of thermal plant	(%)
$\phi_{LV\text{-}0Q}$	power factor angle at LV terminals at zero VAr condition	(radians)

C

MAINTENANCE AND REPAIR COST ALLOCATION

Maintenance and Repair Cost Allocation

The following pages describe various maintenance activities and fault conditions. These are also summarized in Proforma 1. To take account of the maintenance cost of VAr production it is necessary to assign some costs to Proforma 1. The items listed are intended to be an aid-memoir and it is not expected that it will be possible to assign costs to each individual item. In fact it would be reasonable to simply assign one total cost per main group such as stator repairs if it proved impossible to separate costs to the level of detail presented in Proforma 1.

Methodology

Materials used in the construction of electrical machines are subject to various ageing mechanisms such as temperature, cyclic stresses wear and abrasion. Since these phenomena are generally related to the magnitude of the electrical loading applied to the equipment, is reasonable to suppose that maintenance costs associated with running the machine, and indeed the ultimate service life of the machine, is related to the VAr production.

Any ageing mechanism will be affected by loading or cycling effects. Electrical loading can be broken down into the individual relationships of the voltages and currents applied to the generator, generator transformer and excitation system. Each mechanism can be examined and assigned a relationship to Load Phase Current I_a, Excitation Current I_f and Voltage, V. It is also possible to take account of the armature and field winding temperatures, T_a and T_f , should a more detailed analysis be required.

In order to assess the affect VAr production may have on the cost of running a particular generating unit, the usual maintenance activities and possible faults and defects have been broken down into sub groups and assigned a relationship.

To perform the analysis it is necessary to have a either a knowledge of the maintenance cost history of the machine concerned or the history of one or more similar machines. Alternatively it may be acceptable to estimate future costs using best engineering judgment based on typical expectations of service life expectancy.

The following gives some explanation of the items listed in Proforma 1, the item numbers are correlated with the proforma.

1.1 Stator Inspections

The opportunity to inspect the generator is generally determined by the need to inspect steam raising plant pressure parts. However, the need to inspect the generator and the extent of such an inspection will be determined by the likelihood of defects being found. Defects which worsen with prolonged operation such as slot wedge looseness and end winding slackness are the main drivers. Since experience has shown that the majority of these defects are VAr related it is reasonable to conclude that the need and detail of stator inspections is also VAr related.

1.2 Stator Winding

Stator windings is a main group and it may not be possible to segregate costs further than this. However should the data be available the following sub groups divide up the damage mechanism more precisely.

1.2.1 Sub Conductor Cracking

Water cooled generators may be subject to sub conductor cracking due to a variety of short-comings in the design or manufacturing process. When a generator is susceptible to sub conductor cracking, the failure mechanism is generally a high cycle fatigue fracture caused by endwinding vibrations. Such failures will therefore be more likely when the generator is carrying a higher electrical load. Sub conductor cracking causes gas into coolant leakage which must be repaired. Outage times for this type of defect may last several weeks. Single events may occur although in some cases type defects can lead to reoccurring problems and multiple outages.

1.2.2 Slot Wedge Slackness and Fretting

There is considerable force exerted on conductor bars as a direct result of the current flowing in them. For this reason it is important that conductor bars are held securely in the winding slots. If movement is allowed to take place, fretting can occur which will itself increase slackness. If left unchecked this phenomena can lead to considerable damage to the winding insulation, wedges and core.

When assessing the correlation of such faults with the production of VArs it will be necessary to assess the exact nature of each individual failure mechanisms. Complex cause mechanisms will require some judgment to be exercised to proportion the associated costs. 1.2.3

1.2.3 Insulation Damage

Insulation failure may be caused by abrasion in the slots, abrasion in the endwindings, worming (of metallic debris) and voltage surges. Clearly voltage surges caused by switching or lightening are not VAr related. Abrasion of the slots and endwindings are due to vibration and are discussed above. Worming is caused by the movement foreign ferrous material which has found its way into the machine or been built in as a result of poor quality control. Such metallic particles are excited by the conductor flux and bore there way into the conductor insulation. When this takes place in the end winding region the result can often be a gas into coolant leak. This phenomena is related to flux density for both its inception threshold and its rate of progress. Flux density is directly proportional to stator current.

1.2.4 Insulation Abrasion (Slots)

This is an effect of slot wedge slackness see 1.2.2.

1.2.5 Switching Surges and Lightening Damage

Switching surges and lightening damage are clearly not VAr related although any damage due to, or linked to pole slipping incidents that were the result of faults occurring when absorbing VArs could be construed as having a bearing on the cost of providing the service.

1.2.6 Other Stator Winding Problems

This section is simply added to ensure data on any miscellaneous costs and damage mechanisms not covered by the other stator winding groups is collected.

1.3 General Endwinding Problems

Inadequate endwinding bracing can to lead problems which generally manifest themselves as endwinding slackness.

1.3.1 Endwinding Slackness and Fretting

Endwinding fretting can be a major problem with some generators; it can be so severe that insulation is completely worn away and in some cases removal of copper can cause gas into coolant leaks to develop. Although tightening work can be carried out it is not always possible to make effective repairs once damage has occurred. Whilst the phenomena can be caused by core ovalizing effects, the predominant cause is related to conductor bar movement which is excited by stator current. This effect is therefore a VAr related damage mechanism.

1.3.2 Endwinding Insulation Abrasion

Endwinding insulation abrasion is a symptom endwinding slackness see above.

1.3.3 Other Endwinding Problems

This section is simply added to ensure data on any miscellaneous costs and damage mechanisms not covered by the other endwinding groups is collected.

1.4 General Core Problems

Core and core back problems can be related to the armature current carried by the generator.

1.4.1 Core End Heating Damage

Core end heating can occur during running high levels of leading VArs and this alone can have a VAr related affect on stator life. Core end heating damage can also be attributed to pole slipping incidents. It could be argued that such incidents are more likely to occur when the generator is operating at high leading power factors, and that the increased risk of damage has a cost.

1.4.2 Core Damage

Core damage is generally related to core ovalizing forces which can vary with load. For the purposes of this study they are assumed to be constant and not VAr related.

1.4.3 Other Core Problems

This section is simply added to ensure data on any miscellaneous costs and damage mechanisms not covered by the other core problems is collected.

2.1 Rotor Inspections

The opportunity to inspect the generator rotor is generally determined by the need to inspect steam raising plant pressure parts. However, the need to inspect the generator rotor and the extent of such an inspection will be determined by the likelihood of defects being found. Defects which worsen with prolonged operation such as slot cell migration or copper distortion are possible drivers. Since experience has shown that the majority of these defects are VAr related it is reasonable to conclude that the need and detail of rotor inspections could also be considered as VAr related.

2.2 Rotor Vibration

Rotor vibration can be a cause of operational restrictions, forced outages and increased maintenance. Causes are numerous and include, displaced retaining-rings, displaced packing blocks, slip-stick problems, inter-turn faults and asymmetric ventilation. To some extent all of these may be related to temperature and are therefore exacerbated by increasing rotor current squared.

2.2.1 Displaced Retaining-rings

Retaining-rings can become displaced for a number of reasons and it is possible that thermally induced winding movement can contribute to the problem.

2.2.2 Displaced Packing Blocks

Rotor winding heating is capable of causing movement which can slacken rotor endwinding blocking. Also creep which will permanently distort the winding can lead to loose blocking which may cause abrasion damage latter.

2.2.3 Stick-Slip Problems

Stick-slip problems are the direct result of field winding heating and will cause vibration which can often only be reset by returning the rotor to turning-gear speed.

2.2.4 Inter turn Heating

Winding inter turn faults which are current carrying will reduce losses in the turns shorted out causing asymmetric heating which will bend the rotor giving rise to an out of balance effect. The cause may or may not be due to rotor current. However the effect is certainly dependent on the magnitude of the rotor current the generator requires and the vibration problems which occur are sensitive to the VAr generation level imposed.

2.2.5 Asymmetric Ventilation

Asymmetric ventilation is caused by blockage of cooling ducts and this generally causes vibration due to a thermally induced rotor bend. The cause of the problem may not be due to VAr production but the effect and control of the problem is thermally dependent and related to I_f^2 R heating and hence the level of VAr production.

2.3 General Rotor Winding Problems

In general rotor winding problems are affected by stop/start cycles or excitation current or both. A proportion of the cost associated with maintaining the rotor could reasonably be allocated against I_f^2.

2.3.1 Rotor Ground Faults Caused by Contamination

Rotor ground faults may not immediately affect operational performance however it is unusual to tolerate a prolonged period of running with a known rotor ground fault due to the potential for a second ground fault to cause major plant damage. Ground faults can result from a variety of causes. Contamination, cracked liners, interturn faults, broken crossovers, radial lead and field lead failures can all cause rotor ground faults. Rotor ground faults caused by contamination are not VAr related.

2.3.2 Ground Faults Caused by Cracked Liners

Cracked liners are generally the result of slackness, stop start cycles and manufacturing defects and not generally considered to be VAr related. It is however possible that thermally induced winding movement will contribute.

2.3.3 Ground Faults Caused by Inter-turn faults

Rotor interturn faults may result from a variety of causes. Thermally induced hot spots, copper movement or insulation movement is generally thermally induced and will be related to current squared. On the other hand such causes as contamination or overvoltage breakdown are not VAr related.

2.3.4 Ground Faults Caused by Broken Crossovers

Pole to pole crossovers can become broken and cause ground faults and winding open circuits. The problem is generally due to creep caused by over heating and stop start cycles. All of this damage can be attributed to the heating effect of the field current since the stop start cycles would have no effect if the copper remained at an operating temperature below its plastic deformation limit.

2.3.5 Ground Faults Caused by Radial Lead and Field Lead Failure

Radial lead failure is not generally attributed to current loading but some field lead problems may have some component of current involved in the development.

2.3.6 Ground Faults Caused by Hot Spot Overheating

Hot spot overheating is directly related to the thermal effects of I_f^2 R heating.

2.3.7 Inter-turn Faults Caused by Contamination

Inter-turn faults caused by contamination are not the result of VAr production. However the operational effects of the inter-turn fault will be VAr dependent.

2.3.8 Inter-turn Faults Caused by Insulation Movement

Inter-turn faults caused by insulation movement can be considered as VAr related as the movement is generally thermally induced by winding expansion and contraction.

2.3.9 Inter-turn Faults Caused by Hot Spot Overheating

Hot spot overheating is directly related to the thermal effects of I_f^2 R heating.

2.3.10 Over Voltage Breakdown

Over voltage breakdown is possible due to the voltages induced during pole slipping. While the damage mechanism is a stability issue, it is possible to argue that the pole slip may have been caused by a VAr related problem such as the requirement to operate close to the stability limit at a leading power factor.

2.3.11 Other Rotor Winding Problems

This section is simply added to ensure data on any miscellaneous costs and damage mechanisms not covered by the other rotor winding problems is collected.

2.4 General Mechanical Problems

Mechanical problems are not generally VAr related. However, there may be problems as a result of secondary effects due to temperature or vibration.

2.4.1 Forging Cracks

Cracking of generator rotor forging cannot generally be related to increased rotor current and are not therefore VAr related. However, some links with increased operating temperature are possible.

2.4.2 Other Mechanical Problems

This section is simply added to ensure data on any miscellaneous costs and damage mechanisms not covered by the other rotor mechanical problems is collected.

2.5 Brush Life, Slipring Replacement and Refurbishment

Slipring wear rates may be affected by a variety of parameters such as vibration, current density, spring pressure, cooling flow and brush grade. However, experience has shown that where current design densities are high, problems can occur. While a number of factors may be involved, the extent of such problems are generally dependent on the magnitude of the excitation current. Brush wear is affected in a similar way.

Consideration should be given to including a proportion of the costs associated with routine brush replacement, brushgear maintenance, brushgear cleaning, slipring machining and slipring replacement.

2.5.1 Slipring Machining

As discussed above slipring machining may be considered as a VAr related cost.

2.5.2 Brushgear Maintenance and Brush Replacement

Brush wear rate is related to several factors, however, since one of them is excitation current brush maintenance, costs may be considered as VAr related.

3.1 Excitation System Problems

Since the loading on the excitation system is VAr related excitation problems should be considered. Exciters, rectifiers, thyristors, excitation transformers and field breakers could all be considered. However in general excitation systems are generously rated and problems scarce.

3.1.1 Automatic Voltage Regulator Problems

There have been problems where voltage regulators have given problems at high levels of excitation. Where specific problems exist they should be costed against VArs.

3.1.2 Other Excitation System Problems

This section is simply added to ensure data on any miscellaneous costs and damage mechanisms not covered by the other excitation system problems is collected. Troubles with Exciters, rectifiers, thyristors, excitation transformers and field breakers could all be considered here.

4.1 Generator Transformer Inspections

Generally internal inspections of generator transformers are only carried out as a result of problems. Therefore, if the problem is VAr related then the inspection cost can be considered against VAr production.

4.1.1 Transformer Gas in Oil Analysis

The need for gas in oil testing is related to mechanical vibration and heat ageing which are VAr related. It is not unreasonable to propose that if these phenomena did not prevail then testing would be considered unnecessary. A proportion of the costs associated with such tests could therefore be allocated to VAr production.

4.1.2 Tap Changer Inspections

The need to inspect tap changers is related to load and the number of operations. It should also be considered that the tap changer is provided to control VAr import/export and all tap changer costs should therefore be considered as VAr related.

4.1.3 Tap Changer Maintenance

As above- all on load tap changer costs should be considered as VAr related.

4.1.4 Other Transformer Problems

This section is simply added to ensure data on any miscellaneous costs and damage mechanisms not covered by the other transformer problems is collected.