Fixed Costs of Providing Ancillary Services from Power Plants

Reactive Supply and Voltage Control, Regulation and Frequency Response, Operating Reserve - Spinning

TR-107270-V5

Final Report, December 1998

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REPORT SUMMARY

For steam-cycle generating units that want to profitably sell Reactive Supply and Voltage Control (RS-VC), Regulation and Frequency Response (RFR), and Operating Reserve-Spinning (ORS) services, this report describes methodologies to determine fixed costs. The methodologies are designed for "generators" of electricity planning to offer these ancillary services in a competitive market.

Background

With deregulation of the electric utility industry, many "generators" need to know more accurately the costs of various services that they have provided in the past but not priced separately. Knowing the exact cost of a specific service is prerequisite to pricing this service and selling it in a competitive market place. Among the services commonly named "Ancillary Services," the Federal Energy Regulatory Commission (FERC) has, in its Order No. 888, defined a set of six services that it believes must be "unbundled" to provide "open access." Another set of similar services, some with definitions slightly differing from FERC, was created by the Interconnected Operations Services Working Group (IOS-WG) sponsored by NERC. RS-VC, RFR, and ORS appear in both lists.

Objectives

To describe RS-VC, RFR, and ORS and provide methodologies that can determine their fixed costs for a steam-cycle unit at the power station level.

Approach

Project analysts identified two possible methods for determining the capital cost of the station or unit components needed for a specific service. The first method defined the costs (at net book value) of the components identified by plant engineers to produce RS-VC, RFR, and ORS services. The second method consisted of obtaining the current price of installed equipment capable of providing the service and the price for equipment of the same capacity, but not equipped for or capable of providing the service. The project team used a period of one year for their costing methodologies, assuming that the specific service would be provided (or be available) during the entire evaluation period. They further assumed that there was no interaction among services. This assumption meant that fixed costs for one service do not depend on whether another service also is supplied during the evaluation period. While the methodologies

are based on common steam power plant engineering economic and accounting principles, they required input and guidance from many sources to formulate them into a usable form. For implementation and evaluation of the methodologies, the team used Excel® based spreadsheets with real data from participating utilities.

Results

The report describes in detail the methodologies needed to determine the fixed cost for RS-VC, RFR, and ORS, respectively. These methods are shown in spreadsheet form, including descriptions of spreadsheet pages together with calculations for a fictitious unit for each of the three services. The algorithms are listed in their entirety and can easily be used in most available spreadsheet programs.

EPRI Perspective

To offer and profitably sell any of these three services in a competitive market, utilities must understand the fixed costs associated with providing the service. This report will help facilities determine the fixed costs for RS-VC, RFR, and ORS services. Variable costs for these same services have been studied under previous EPRI sponsorship. See these EPRI reports: *Cost of Providing Ancillary Services from Power Plants* (TR-107270-V1: *Primer*; V2: *Regulation and Frequency Response* ; V3: *Reactive Supply and Voltage Control*; and, V4: *Operating Reserve-Spinning*).

TR-107270-V5

Interest Categories

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

Keywords

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ABSTRACT

This report describes methodologies to determine the fixed costs for a steam cycle generating unit to participate in Reactive Supply and Voltage Control (RS-VC), Regulation and Frequency Response (RFR), and Operating Reserve - Spinning (ORS) services. It is intended for use by a "Generator" of electricity who is planning to offer these ancillary services in a competitive market. The methodology is based on common steam power plant engineering and economic principles.

The variable costs of these services may be determined by methodologies documented in other EPRI reports, Ref. 5, 6 and 7.

ACKNOWLEDGMENTS

While the methodologies are based on common steam power plant engineering economic and accounting principles that can easily be recognized by potential users from the utility industry, it required the input and guidance from many sources to formulate it into a usable form. The following people and organizations contributed significantly to this. Their contributions are gratefully acknowledged.

- Murray Davis, Director of Transmissions Detroit Edison Co. for his development of the "Vector Allocation Method" for the fixed costs of Voltage and VAr supply, documented in Ref. 8 and 9.

- Dean Harrington, Generator Systems Consultant, Schenectady, NY, for his clarifications to the internal workings of a synchronous generator in both lagging and leading power factor mode.

- Paul J. Spicer, Sr. Generation Services Engineer, Wisconsin Public Service Corp., Green Bay, WI, for his review of the draft methodologies including many valuable comments based on his detailed participation in the definition and costing of Ancillary Services, based on work for his employer as well as on the IOS WG..

- William F. Benton, Senior Engineer, Allegheny Power Systems, Inc. for valuable help in proof reading as well as for many suggestions to improve readability and explanation of concepts.

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INTRODUCTION AND OBJECTIVE

With the deregulation of the electric utility industry, many “Generators” are facing the need to know more accurately what are the costs of various services, which they have provided in the past but not priced separately. Precise knowledge of the actual cost of a specific service is a prerequisite to pricing this service and selling it in a competitive market place.

Among the services commonly named “Ancillary Services,” the Federal Energy Regulatory Commission (FERC) has, in its Order No. 888 (Ref. 1), defined a set which it believes must be “unbundled” to provide “open access”. These “six services” are listed below. It is noteworthy, that the Commission will allow other services to be unbundled for other reasons.

1. Scheduling, System Control and Dispatch
2. Reactive Supply and Voltage Control from Generation Sources (RS-VC)
3. Regulation and Frequency Response (RFR)
4. Energy Imbalance
5. Operating Reserve - Spinning Reserve (ORS)
6. Operating Reserve - Supplemental Reserve

Another set of services, some with definitions slightly differing from the “six services”, was created by the Interconnected Operations Services Working Group (IOS-WG) sponsored by NERC. The IOS-WG has defined ten ancillary services.[1] (Ref. 2) These services were defined, as those, which NERC will require to ensure reliability of electric supply in a deregulated environment.

[1] “Defining Interconnected Operations Services Under Open Access” M. Terbrueggen, Members of the Interconnected Operations Services Working Group, R Adapa and Donald Benjamin, EPRI and NERC, May 1997

The ten services are:

1. System Control

2. Reactive Supply and Voltage Control

3. Regulation

4. Energy Imbalance

5. Operating Reserve - Spinning

6. Operating Reserve - Supplemental

7. Load Following

8. Real Power Transmission Losses

9. Dynamic Schedule

10. Black Start Capability

NERC has continued the work on these services by an Interconnected Operations Services Implementation Task Force (IOS-ITF). At the time of writing, this work had resulted in a draft "Policy 10 - Interconnected Operations Services" dated April 7, 1998, (Ref. 3). Its purpose is to define the requirements regarding each service needed to ensure reliability of the supply under open access.

Of the above listed services, the present report will consider only three:

1. Reactive Supply and Voltage Control

2. Regulation and Frequency Response

3. Operating Reserve - Spinning

Reactive Supply and Voltage Control (RS-VC), Regulation and Frequency Response (RFR), and Operating Reserve - Spinning (ORS) are newly defined separate services that can be offered and sold by a "Generator" of electric power. In this study, these services are understood to be provided at the station or unit level. And the fixed costs for the services are defined at this level. The term "fixed" in accounting is understood to be "A cost that remains the same in total as activity increases or decreases..."[2].

Fixed costs can also be defined as the costs incurred by an organization that are not variable with respect to production. One analysis for determining whether or not to produce or provide is the contribution margin (CM) method. When using the CM method, all costs associated with production are subtracted from sales to produce the CM for the product or service. If the CM is large enough to cover non-production cost, profitability may be attainable. Under the CM method, in addition to asset costs, costs like real estate taxes, insurance premiums and depreciation are considered fixed costs that must be covered by the CM. The spreadsheet developed for this project allows the user to enter costs other than the standard asset costs.

The main objective for the costing methodology is to identify the fixed costs associated by the power plant unit providing RS-VC, RFR, and ORS services for a specific period of time. In this report a period of one (1) year is used. (Other time periods can be used by appropriate correction to the cost factors). This means that it is assumed that the specific service will be provided (or be available) during the entire evaluation period. It is further assumed, that there is no interaction among the services, which means that the fixed costs for one service does not depend on whether another service is also supplied during the evaluation period.

Identification of the components or capacity needed to provide the services will allow for the allocation of the portion of station or unit fixed costs to be assigned to each of the three ancillary services.

We identified two possible methods for determining the capital cost of the station or unit components needed for a specific service. The first method is to define the costs (at net book value) of the components identified by plant engineers as required to produce RS-VC and RFR, and ORS services. With component costs and the specific machine capabilities understood, allocation of plant or unit costs can be applied to the services.

The second method consists of obtaining from the original equipment manufacturer (OEM) the current price for the equipment installed (which is capable of providing the service) as well as the price for equipment of the same capacity, but not equipped for or capable of providing the service. This method is most practical if only one or a few major pieces of equipment are involved. For example for the RS-VC service, extra capital cost could be obtained by comparing the cost of the installed generator with one of the same kW capacity but rated at power factor PF =1.0. If the OEM can also provide the extra cost for generators of the same kW capacity but rated at successively lower

[2] Accounting for Costs as Fixed & Variable, Maryanne M. Mowen, Ph.D., CMA, National Association of Accountants, 1986, page 5

PF's a formula or curve of capital cost versus PF can be obtained. Applying this formula or curve to the plant's historical costs will provide the additional fixed cost for equipment required to provide the RS-VC service as opposed to not providing the services.

Allocation of a plant or unit's fixed cost to one of the three services is recommended for major repair, replacement, or upgrades as well. Any allocation method for proportioning fixed costs to services must have some rationale that approximates wear and tear or depletion of the assets over time or usage. Examples of methods that can provide such answers are: unit capacity, operating time and the vector analysis for RS-VC developed by Murray W. Davis.[3] (Ref.8 and 9)

Allocation of fixed costs by the first method will often require some judgment. This is especially true for components or subsystems in a power plant, because many of them serve several purposes. A couple of examples will illustrate this.

The control valves of a steam turbine are absolutely required for at least the following functions (some of which are ancillary services): Startup, i.e. acceleration and synchronization of the unit; Loading and Unloading, i.e. Load Following as well as Operating Reserve-Spinning; small, rapid load changes, i.e. Regulation and Frequency Response; rapid closure on load rejection or unit trip, i.e. Protection.

A coordinated boiler turbine control system, similarly, may be said to serve at least for Load Following, Regulation and Frequency Response, and Operating Reserve-Spinning. Similarly, the excitation system for the electric generator can be said to be required both for energy production (kWh), and Reactive Supply and Voltage Control.

In judging what fraction of a component or subsystem serves a specific service it is advisable to look for a “cause and effect” or “degree of need”. If at all possible, the effect or degree should be based on physical reasoning or engineering calculations. An example of the latter will be found under RS-VC “ Vector Allocation Method”.

Excel® based spreadsheets were used for implementation and evaluation of the methodologies. A demonstration calculation is included for each of the three services. The algorithms used are listed and can easily be implemented on most available spreadsheet programs.

[3] “Vector Allocation Method for Determining Voltage Control and Reactive Supply Costs, Murray W. Davis, December 1997, EPRI Services Workshop.

2

PROJECT BACKGROUND

Before the deregulation of the electric utility industry, Reactive Supply and Voltage Control, Regulation and Frequency Response, and Operating Reserve - Spinning were provided as an integral part of the supply of electric power from power stations or "Generators". A certain number of Generators participated in these services, and the cost of their participation was simply part of the energy costs from these units. The amount of generation capacity that was needed to participate was determined either by the utility, the Area Generation Control center or a larger power coordinating entity, often to comply with NERC requirements.

In the future, it is expected that the Operating Authority (OA) such as an Independent System Operator (ISO) will be responsible for maintaining the integrity of the system. These responsibilities are currently being spelled out by NERC in the aforementioned draft "Policy 10 - Interconnected Operations Services", (Ref. 3).

Because, the OA does not produce any power, (it is not a Generator), it will need to purchase ancillary services separate from the main product, i.e. electric energy. A number of Generators will find it profitable, or be required to offer some or all of the ancillary services to the ISO. In order to offer and sell a service with a profit in a competitive market, it is necessary to understand the fixed costs associated with providing the service. The variable costs have already been studied under EPRI sponsorship. See EPRI Reports: "Cost of Providing Ancillary Services from Power Plants", TR-107270-V1; (Ref.4), -Regulation And Frequency Response, TR-107270-V2; (Ref.5); -Reactive Supply and Voltage Control, TR-107270-V3; (Ref.6), and -Operating Reserve - Spinning, TR107270-V4, Ref.7).

Therefore, the objective of this study is to describe the services and provide the methodologies that can be used to determine the fixed costs of the services for a steam cycle unit at the power station level. The work was done under contract with EPRI and with the cooperation and inputs from several utilities.

3

METHODOLOGY FOR "REACTIVE SUPPLY AND VOLTAGE CONTROL (RS-VC) SERVICE"

Project Background

Before the deregulation of the electric utility industry, RS-VC was in general provided by each utility to cover its own load or organized by an Area Generation Control center to cover the load inside the particular area. The fixed cost of RS-VC has in most cases probably not been calculated separately, but simply been considered as part of the fixed costs related to the entire plant.

In the future, it is expected that the Operating Authority, (OA), such as an Independent System Operator (ISO) or other equivalent entity will be responsible for maintaining RS-VC system wide. Because the ISO does not produce power, it will need to purchase the service separate from the main product, i.e. electric energy; and it is expected that a number of generators of electricity will find it financially attractive, or be required, to offer the service for sale to the ISO. In order to offer and sell a service with a profit in a competitive market, it is necessary to understand the fixed cost of the service. Even while the service is regulated, the sum of variable and fixed cost is likely to be a valuable support for tariff approval.

Therefore, the objective of this study is to define briefly how the service can be provided, and to furnish a methodology to calculate the fixed cost of this service when supplied from a unit at the power station level.

Definition of Fixed Costs of Voltage Control and VArs

FERC Order 888

In its Order 888 (Ref. 1), FERC's conclusions regarding RS-VC are as follows:

"We accept NERC's identification of two ways of supplying reactive power and controlling voltage. One is to install facilities, usually capacitors, as part of the transmission system. We will consider the cost of these facilities as part of the cost of basic transmission service. Providing reactive power and voltage control in this way is not a separate ancillary service.

The second is to use generating facilities to supply reactive power and voltage control. This use is the service named here, which must be unbundled from basic transmission service."[4]

Interconnected Operations Services Working Group (ISO-WG)

The ISO-WG report states that, "RS-VC ---provides reactive supply through changes to generator reactive output to maintain acceptable transmission system voltages and facilitate electricity transfers"[5] and provides, "--the ability to continually adjust transmission system voltage in response to system changes."[6] The report further states that, "--the rationale for Reactive Supply and Voltage Control from Generation Sources as a separate service is twofold. First, the costs incurred by Transmission Providers that also own generation are in production accounts, not transmission accounts, and thus Transmission Providers do not receive compensation for this service as part of their transmission tariffs. Second, entities other than Transmission Providers that own generation may be able to supply reactive power to the transmission system and should receive appropriate compensation."[7]

Both FERC and ISO-WG have stated that Generators may be able and wish to participate in providing RS-VC. Because Generators have the option to provide this service, it should be costed for supplying the service to the grid. Even when the Generator is obligated to provide the service, computation of the cost may be necessary to support the tariff.

Discussion On The Methodology for RS-VC

When purchasing generating equipment, the purchaser can and does decide what power factor (PF) the generator shall be capable of operating at. The rated PF determines the maximum phase shift between the voltage and current for a particular generator while providing rated power. A Power Factor of one (also known as unity PF) denotes that the voltage and current are in phase. Power factors equaling less than one denote that the voltage and current are out of phase by the arc cosine of the power

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[4] Docket Nos. RM95-8-000 and RM94-7-001 pages 209-210
[5] Defining interconnected operations services under open access, copyright 1997 Electric Power Research Institute, Inc., page 7
[6] Defining interconnected operations services under open access, copyright 1997 Electric Power Research Institute, Inc., page 23
[7] Defining interconnected operations services under open access, copyright 1997 Electric Power Research Institute, Inc., page 47

factor. Power factors are further characterized as “lagging” meaning that the current lags behind the voltage in time, or “leading” when the opposite is the case.

When the power factor is less than one and lagging (the most common operating mode), a generator will consume a little more energy to attain the rated power output at its terminals. (This extra power and the resulting “variable” cost is analyzed in Ref. 6). A generator can influence the power factor by adjustments to its field current (implemented by its voltage control system). Reactive supply (RS) or VArs are produced by adjusting the phase angle. VArs are a measurable output from the electric generator. At present, it is uncertain whether an open market for VArs can or will be developed, because VArs can not be transmitted freely over an extended distance. Rather, VArs must generally be produced “locally”, i.e. fairly close to where they are consumed.

Generators who elect to, or are obligated to, control their machines to produce RS-VC when requested by the OA do not do so without additional costs. The variable costs have been analyzed in EPRI TR-107270-V3, Ref. 6. They are caused mainly by the fact that the internal losses in the generator and step-up transformer will rise because the actual currents are higher, and it will require extra fuel to cover these losses.

The fixed costs for producing VArs are located in the generator stator and rotor, cooling system, exciter, and the control components of the unit or power station. The step-up transformer is electrically a part of the generator and may need to be included in this list of equipment if it is dedicated to a specific unit and not considered part of the switchyard. The fixed costs of these components are the subject of the following analysis.

The inclusion of the step-up transformer in the equipment required to produce RS-VC is appropriate if it is desired to determine the fixed costs of the power and ancillary services of the unit delivered at the high voltage level. This point of delivery is also used in the methodology for the variable cost of RS-VC, Ref. 6. However, if the fixed costs are to be determined at the generator terminals, the step-up transformer becomes part of the switchyard and transmission system, and its cost and the losses in this transformer must be accounted for under transmission.

There is one more effect of RS-VC that may be considered a fixed cost for this service. As mentioned above, the generator will consume more power at rated output when providing RS-VC service and the turbine and boiler must produce this extra power. The cost of the extra power is calculated under the variable cost (Ref. 6). The additional turbine and boiler capacity represents an additional capital cost of equipment that is only needed to be able to operate in RS-VC mode. This added capacity can be included in the methodology by using the extra losses from the variable cost calculation to determine the additional turbine and boiler capacity required and from that the fixed cost of this capacity.

The capital cost of the extra turbine generator capacity can be determined as the ratio of this capacity relative to rated capacity multiplied by the capital cost of the unit or plant.

Gathering cost data is the beginning process for any allocation of fixed costs to products or services sold or supplied. Since the major components used to produce RS-VC, the generator, exciter, step-up transformer (if applicable) and associated controls are also used to produce energy, the allocation of these assets to RS-VC will be done in three steps. The first step is to identify the costs of the components. The second step is to allocate the costs to RS-VC. The third step is to apply the annual Cost of Capital Factor to allocated costs. When the steps are completed the fixed costs associated with RS-VC for one year will have been identified.

One approach for determining the basis of fixed costs, is to review accounting data to get the original purchase price of assets. Another approach is to use current Original Equipment Manufacture's (OEM) prices and to discount those prices back to the year of purchase for the assets under review.

Two methods for allocating the fixed asset cost for RS-VC are feasible. The authors believe that both methods are worthy of review. The first method for allocating the identified fixed costs to RS-VC, a.k.a. the "One minus power factor" method is to use "one minus rated power factor", (1-PFr), as a measurement of the amount of fixed costs of the entire generator associated with its RS-VC capability. See Figure 3-1. This method is based on the assumption that the cost of the entire generator system is proportional to its kVA rating and that the portion of the rating not used for kW production is serving the RS-VC supply. As Figure 3-1 shows, 1-PFr is this portion. A variant of this method is to use the average power factor, (PFa) that the Generator ran at throughout the year. The rationale to this method is that when the Generator runs at something other than the rated power factor, PFr, the allocation of the fixed costs must be adjusted because the generator could have supplied additional output. By using the average PFa, the variations over time are accounted for.

The second allocation method is the use the Vector Allocation Method (or a modification thereof) as presented by Murray W. Davis in testimony to The Federal Energy Regulatory Commission (FERC), Docket No. OA96-78-00 (Ref. 9) and summarized in an EPRI sponsored workshop (Ref. 5) to calculate the fraction of generator fixed cost to be allocated to the supply of RS-VC, see Appendix 1.

The method relies on an electrical analysis of the magnitude of rotor field current and stator armature current to be carried in support of Watts, VArs and Voltage, all as function of PF and calculated from existing generator data. The method then assumes that the fixed cost of the stator and rotor systems can be allocated to providing Watts, VArs and Voltage in proportion to the currents related to these quantities. It is finally assumed, that the VArs and Voltage portions together serve the supply of RS-VC and the Watts portion serves the energy supply (kWhs). The authors disagree with the lumping together of the VArs and Voltage portions because, the latter is not the one serving voltage control but rather the portion required to provide rated voltage at no load. The modified method consists of allocating the voltage portion to the Watts production.

The output of the analysis is a percentage of total fixed costs of generator stator and rotor system (and step-up transformer if applicable) to be applied to each of the two services RS-VC and kWh.

Detailed description of the Vector Analysis Method may be found in Appendix 1.

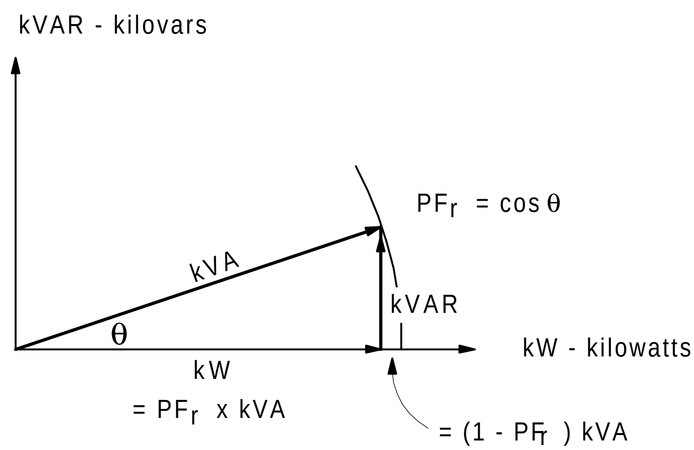


Figure 3-1
Generator Phasor Diagram

The authors believe that because the concept suggested by Mr. Davis is based in the physics of the machinery, the modified version should be given first consideration as the method for allocating fixed costs to RS-VC.

Once the allocation method is established and the fixed costs of the equipment supporting RS-VC are determined, then the yearly or other periodic cost needs to be identified. Multiplication by the Cost of Capital[8] factor for the Generator is an accepted method for determining the periodic costs. The Cost of Capital is the rate of return that a corporation must pay for its invested capital. This rate is important for all financing decisions because it comprises all the elements of a business' operation and is the minimum rate that is needed to satisfy all fees, taxes and services due as well as the

[8] "The cost of capital is the rate of return a firm must earn if it is to meet the promises to, and expectations of, investors who now are contemplating purchase of its securities. If a corporation is to fulfill its objective of increasing the wealth of its owners, it needs to earn more than its cost of capital." Self-Correcting Problems in Finance, 3rd Edition, Roland I. Robinson and Robert W. Johnoson, 1976, Allyn and Bacon, Inc. page 133

required return to its investors (both bond and equity holders). Moreover, the Cost of Capital factor should be readily available in most financial organizations

Components Needed for Cost Analysis for RS-VC

Detail costs of Generator Unit = "Stator" i.e. [Stator + Cooling System + other support systems] + "Rotor" i.e. [Rotor + Cooling System + Excitation Source (rotating or static) + Controls} + Step-Up Transformer (if not part of the switchyard). ($)

PF at rating of generator or desired point of analysis, PF_r or PF_a (per unit)

Cost of Capital factor (k) = Cost of Financing (% per evaluation period (year))

further, for method number two:

OEM Cost (OEM)= Cost of New Equipment at fixed kW capacity and different PF ratings ($)

For the vector allocation method:

Capacity diagram for the generator (see Figure A-2 in the Appendix)

Synchronous Reactance, X_d = reciprocal of short circuit ratio SCR (per unit)

For all methods:

The extra power required from the boiler and turbine to operate at the power factor; the ratio of this power to the total power of the unit, and the fixed cost of the relevant part of the unit or plant.

Step-By-Step Functional Specification of Methodology RS-VC

1. Identify the fixed costs of the Generator, Exciter, Stator, Rotor and associated controls as well as of the step-up transformer (if applicable)

2. Identify the fixed shared resources and unit specifies non-generator costs to be used for calculating the cost of support equipment

3. Define allocation method to use

4. Apply allocation method to the fixed costs

5. Multiply the fixed cost for RS-VC support equipment by the Cost of Capital (% per evaluation period)/100

4

METHODOLOGY FOR "REGULATION AND FREQUENCY RESPONSE SERVICE"

Definition of Fixed Costs for Regulation and Frequency Response (RFR) Service

FERC Order 888

In its Order 888, (Ref. 1), FERC states that in a deregulated electricity supply market: "Someone must supply extra generating capacity, called regulating margin to follow the moment-to-moment variations in the load located in a control area. Following load variations is necessary to maintain the scheduled interconnection frequency at sixty cycles per second (60 Hz)."

Following a discussion of utility comments FERC concludes that: "Regulation Service and Frequency Response Service are the same services that make up the Load Following Service referenced in the NOPR (Notice of Proposed Ruling). While the services provided by Regulation Service and Frequency Response Service are different, they are complementary services that are made available using the same equipment. For this reason, we believe that Frequency Response Service and Regulation Service should not be offered separately, but should be offered as part of one service."

Interconnected Operations Services Working Group (IOS-WG)

The IOS WG report (Ref. 2) contains the following definition of Regulation: "The provision of adequate generation response capability, under Automatic Generation Control (AGC), in order to continuously balance Control Area supply resources with minute-to-minute load variations in order to meet NERC Control Performance Standards". This definition differs from FERC's proposed definition on two distinct points:

- Regulation is for the purpose of a Control Area resource balance, and the function is performed minute-to-minute

- There is no mention of frequency control, which requires moment-to-moment action, i.e. within seconds.

Definition for this Study

The two definitions quoted above are not identical. Many (maybe most) AGC signals contain a frequency correction. Hence, operating under AGC will automatically lead to some degree of frequency regulation. Further, any steam turbine with an active speed control/governor system will participate in frequency regulation. Therefore, it became necessary to determine which definition to adopt in this study.

For this methodology (as in EPRI TR-107270-V2) no distinction is made between Regulation Service and Frequency Response Service. The definition implied by FERC's Ruling 888 is adopted. This means that "Regulation and Frequency Response Service" shall include all rapid load changes ("moment to moment", including "minute-to-minute") whether their purpose is to meet the instantaneous load demand, to balance Control Area supply resources with load, or to maintain frequency.

Discussion Of The Methodology For Regulation and Frequency Response

When a Generator decides to participate in frequency regulation, a steam turbine unit must be in an operating mode that allows it to increase its load fast in response to changes in frequency detected by its speed governor or to meet an ISO AGC signal to change load. Signals may be sent every 3 to 5 seconds requiring the unit to increase or decrease its load. The ability to receive the AGC signal and quickly move from one load to another may require additional equipment and control systems to respond quickly to new load requirements. Equipment needed for responding to RFR includes: telemetering equipment, AGC equipment, control systems designed for rapid response, coordinated boiler control systems and the remainder of the plant or unit.

The authors identified two distinct methods to calculate the fixed costs of RFR. One method is to identify and find the cost of each component related directly to RFR and to divide components that share RFR duties with energy producing duties on some rational basis. This method will, in most cases, require a lot of research of cost data as well as judgment in allocation. And it is likely to be open to challenges and differing opinions. The spread sheet implementation has an option for this method, but in many cases it may not be the preferred one.

The second method uses the actual regulating margin bandwidth, which the unit will be adjusted to and is capable of supporting. This regulating margin may come from a contractual requirement to determine the highest load response increment above the mean load required for load following. Once this additional capacity (regulating band width) is determined for providing RFR as the highest load peak, (for an example see

Figure 4-1), the allocation of a share of the entire plant for RFR is determined. For example, if 30 MW is required for RFR and the plant/unit is rated at 500MW then 30/500 = 6 % of the plant's fixed costs are to be allocated to RFR. The regulating band width may be determined by the bids being sought by the OA or ISO or by the plant's optimal operating mode and must, of course, also be within the capability of the unit both as regards rate (e.g. MW/min) and magnitude (total MW).

The rationale for the fixed cost allocation per Figure 4-1 is as follows. If the unit did not participate in frequency response, it would operate according to the load line labeled "Mean Load Line" and deliver energy (kWh) equal to the time integral of this load over time. In determining the cost of this power delivered, a fixed cost would be allocated according to the capacity used, that is for the capacity up to the line "Mean Load Line." When the unit participates in frequency response per Figure 4-1, it will deliver the same energy (kWh) as if it did not, because that is how the mean load line of the figure is drawn. Thus, the fixed cost of capacity up to the mean load line will be included in the cost calculation for power delivery. The extra capacity required (area above the mean load line), will, however, not be included in the fixed cost of capacity for power delivery and, therefore, constitutes that part of the unit capacity engaged in frequency control. The fixed cost of this part of the plant capacity is the cost to be allocated to participation in frequency response.

At least one utility, which reviewed this methodology, believed that the full range of rapid load variations in Figure 4-1 constitutes the part of unit capacity reserved for RFR service. If, for example the full range were +/- 30MW for a 500 MW unit, then 60/500 = 12% of the plant's fixed cost are to be allocated to RFR. The rationale for this allocation is that if the unit did not participate in RFR service, then it could have produced a steady load up to the line at the top of the load variations shown in Figure 4-1. The selection of the full range of load variations (i.e. of +/-X MW) is allowed for by user selection in the spread sheet implementation of the methodology.

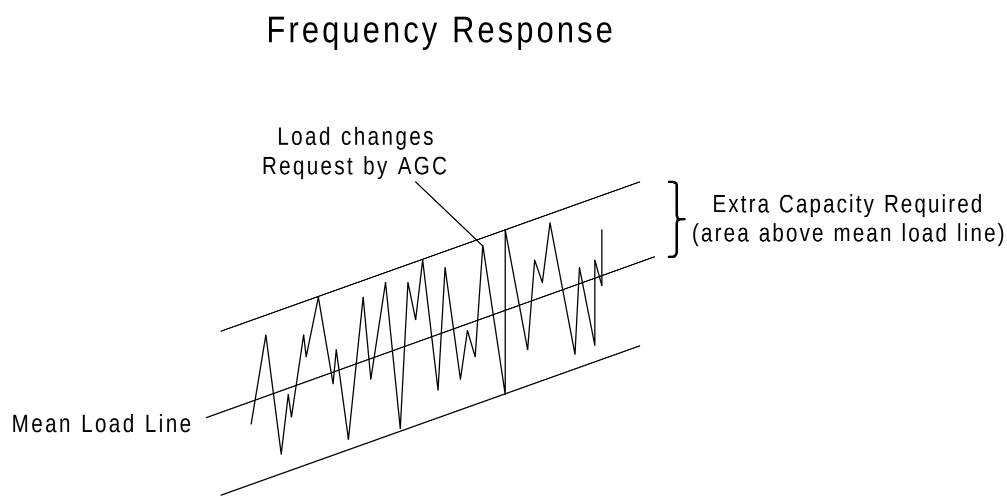


Figure 4-1
Frequency Response

Once the cost of components and/or cost of a fraction of plant capacity engaged in RFR have been determined, the Generator's Cost of Capital factor is applied to the costs to find the fixed cost of RFR per year (or other evaluation period).

Components Needed for Cost Analysis for Regulation and Frequency Response

- Total Cost of the plant (with one unit) or total unit cost
- Equipment costs associated directly with RFR
- Equipment costs of shared components allocated to RFR

<u>or</u>

- Regulating margin requirements for RFR or data from past experience or telemetering data that shows the AGC signal to increase load for a short duration
- The amount of load required meeting the AGC signal above mean load requirements

Step-By-Step Functional Specification of Methodology RFR

For the first methodology do the following:

- Identify the costs for assets associated with RFR (telemetering, AGC equipment, fast control system, coordinated boiler/turbine controls, etc)
- Estimate percentage of other assets associated with RFR
- Apply percentage to other assets cost
- Sum all estimated costs associated with RFR
- Apply the Cost of Capital factor to the costs associated with RFR

For the second method:

- Identify the fixed costs of the unit
- Review mean load requirements or AGC signal data to determine the largest load requested for RFR
- Determine the percentage of capacity that must be held in reserve for RFR relative to rated capacity
- Multiply percentage of capacity held for RFR against total unit costs to determine RFR fixed costs
- Apply Cost of Capital factor to RFR fixed costs

5

METHODOLOGY FOR "OPERATING RESERVE - SPINNING" (ORS)

Definition of Fixed Costs for Operating Reserve-Spinning (ORS)

FERC Order 888

In its Order 888, (Ref. 1), FERC states that in a deregulated electricity supply market there will be a need for two types of "operating reserve", i.e. "spinning reserve" and "supplemental reserve". Quoting from FERC: "Spinning reserve is provided by generating units that are on-line and loaded at less than maximum output. They are available to serve load immediately in an unexpected contingency such as an unplanned outage of a generating unit." This is separate and distinct from "...supplemental reserve which is also generating capacity that can be used to respond to contingency situations. Supplemental reserve, however, is not available instantaneously, but rather within a short period (usually ten minutes)." The reason for distinguishing between these two ancillary services, is that they "…may be subject to different reliability requirements; the resources that supply each service may not be the same; and the two services may be provided by different suppliers."

Interconnected Operations Services Working Group (IOS-WG)

The IOS-WG report (Ref. 2) contains the following definition of Operating Reserve - Spinning: "The provision of generating capacity synchronized to the system that is unloaded, is in excess of the quantity required to serve current anticipated demand, is able to respond immediately to serve load, and is fully available within ten minutes."

The IOS-WG report contains a more detailed definition and discussion of this service. From this discussion we note specifically that "...only on-line and synchronized capacity that a generator can supply within ten minutes shall qualify as ORS." Further, that "...once the ten minutes have elapsed, the resources must have an additional twenty minutes sustained energy producing capability-"during which supplemental reserves can be activated to allow the ORS resources to be returned to spinning reserve status within thirty minutes after activation.

Definition for this Study

The basic definitions quoted above appear to agree quite well. The details in the IOS WG report go a good deal further than FERC's. Where there may be differences we shall refer to FERC. Therefore, this methodology was developed to determine the Fixed Cost of providing FERC's Ancillary Service number (5), "ORS", as described above.

Means of Implementing Operating Reserve - Spinning

Per definition, ORS must be supplied from operating units that are synchronized to the grid, operating at less than their rated capacity and capable of increasing their net output rapidly, at a defined rate, in response to suitable commands. There are two automated inputs to a steam turbine that enable it to provide ORS: the turbine speed control or governor error signal and the AGC (area generation control) signal. Further, an operator may adjust the load reference (speed/load changer) directly to increase load in response to a request.

Discussion Of The Methodology For ORS

Operating Reserve - Spinning requires (as stated above) that the unit under study must be operating and that excess capacity can be made available. The generator must be partially loaded for example, loaded at 350 MW out of a 500 MW rating so that the ORS capacity, which has been purchased but not used, is available upon demand. The amount of ORS that any Generator may offer for sale is based on the amount of additional capacity it can supply within 10 minutes. The change in output for a given period of time is referred to as the unit's "ramp rate." An often-quoted experience factor for maximum ramp rate of a steam cycle unit is 1% of rating per minute. For example, a 500 MW machine with a ramp rate of 1% and operating at 400 MW will be able to provide 50 additional MW to the grid in a 10-minute period.

Of course, the specific capability of the unit being analyzed should be used if it is known, rather than a general experience factor.

Allocating a plant or unit's fixed costs for ORS is now straightforward. Because the basis for the allocation is capacity, the ratio of ORS capacity to rated capacity is applied to the unit or plant's total cost which yields the cost of fixed assets associated with ORS. We recommend using the total costs of the unit or plant because, being ready to supply ORS means that all components of the total unit or plant must have the capacity to yield 10%, (or the applicable percentage factor for the specific unit), more output.

Once the fixed costs of ORS have been identified, the Generator's Cost of Capital is applied to the total to yield the cost for ORS for the year (or applicable evaluation period).

Components Needed for Cost Analysis for ORS

- Fixed Costs for the entire unit or plant less any costs allocated to other service
- Name plate rating(s) for all unit or plant equipment
- Ramp rate for unit under study and ORS capability to be evaluated
- Cost of Capital percentage/year (or other evaluation period)

Step-By-Step Functional Specification of Methodology ORS

1. Allocate Total Plant Costs Based on Unit's "Name Plate" rating as a percentage of whole plant's capacity
2. Calculate the maximum MW available for ORS by determining the change in output attainable within 10 minutes using the ramp rate
3. Calculate the percentage of ORS based on rating
4. Calculate the Fixed Costs associated with ORS by multiplying the result of item 4 by item 2
5. Apply the Cost of Capital to 5.

6

DEMONSTRATION CALCULATION

6.1 250-MW Unit With Fictitious Data

The methods described in the preceding sections have been implemented in spreadsheet form. Descriptions of the spreadsheet's pages together with calculations, for a fictitious unit, are included in the next few pages.

Caution: This calculation is done with fictitious data; thus, no conclusions should be drawn from this for a specific unit. Only the proper calculation with applicable data can provide valid information.

6.1.1 Input Areas

Shaded fields define all input areas. Shaded fields may require the user to enter specific data or to make choices among a list of defined options.

6.1.1.1 Pages and Descriptions

6.1.1.1.1 Sheet 1: Introduction

This sheet requires that station name and the unit number be entered. The station name and unit number will appear on all sheets. The unit number will be used later for allocation of shared resources

Power Station Name:		**NORTH AMERICAN FOSSIL**
Unit	***8***	**Input Data Sheet**

Input areas are gray scaled.

UNIT DATA ENTRY AREA	
UNIT NUMBER UNDER STUDY	**8**
UNIT RATED MEGAWATTS	250

This spreadsheet with its pages will assist you in determining the periodic fixed costs of supplying Reactive Supply and Voltage Control (RS-VC), Regulation and Frequency Response (RFR), and Operating Reserve - Spinning (ORS).

On this page you may enter the station name. The station name will appear on all subsequent pages. The cell to the right of "UNIT NUMBER UNDER STUDY" must contain the unit number being studied. If this is the first time you are loading information about the station and unit, do not concern your self with the error message appearing below the unit number. However, if you have entered data about the station, then either the MW's for the unit will appear below the unit number or an error message stating that "DATA HAS NOT BEEN LOADED" will appear.

The following is a description of the pages included in this spreadsheet:

SHEET 1: ACCOUNTING DATA

The accounting data page is divided in to six sections. Each section is used through out the spreadsheet for determining the fixed costs. Data that is entered here can either be original purchase price with or with out depreciation, market price, or some other value. The cost of capital is entered here as well as the MW's for each unit located in a station.

Area 1: Cost for shared resources
This section is used for the accounts that are common to the station and not identified with any particular unit. For example the land within the wired fence, the switch yard might be considered shared resources.

Area 2: Non-Turbogenerator cost/unit
This section is for accounts that have been identified as part of the unit under study, but excludes the turbo-generator. Items that might fall in to this section are the boiler, pump, heaters, etc.

Area 3: Turbogenerator cost for unit
This section is for the cost of the turbine, generator, exciter, and step-up transformer (XFO). In this section, you will need to estimate the cost of each component, if actual data is not available.

Area 4: Station data
You will need to enter the MW for each unit at the station. This information is used to prorate the shared resources to the unit under study.

Area 4: Output
The results presented are the asset costs not periodic figures.

Area 4: Cost of capital (% per time period)
Enter the cost of capital for either the company, station or unit. This number will be used later to convert the asset cost to a periodic cost. For the demonstration model the period is assumed to be one year.

SHEET 2: GENERATOR POWER FACTORS:

You must enter at least one power factor rating on this sheet. The power factor choices are Rated (name plate rating), User Defined (any power factor you wish to use in the study), Average Quarterly, Average Monthly, Average Weekly, and Average Daily. The "Average" period power factors are determined by the number of sum of the entries divided by the number of entries. Therefore, if you only enter 350 power factors in the day section then the average is the sum of 350 power factors divided by 350, not 365 or 366.

SHEET 3: VECTOR ANALYSIS

On this page you need to enter only the axis synchronous reactance (Xd) value to compute the fixed costs of RS-VC. The user may also enter the generator losses associated with VAr production. The results on the bottom of the page are labeled Davis Method and Modified Method. The difference between the methods is a result of two different assumptions. Mr. Davis includes the production of voltage as RS-VC, while the modified method uses only VAr production for RS-VC.

The costs of RS-VC are total asset costs from the "Accounting Data" page multiplied by the percentages calculated by the use of vector analysis.

SHEET 4: RFR & ORS

This page has three areas. The first area requires the depreciated costs of RFR, however, it is not necessary to enter any values in this section if you are only estimating RFR as percentage of extra MW required based on MW rating.

The second area is identical to the first section, except the requirements are for ORS.

Area three estimates RFR and ORS based on capacity available. The entries required are the amount of contracted load, the amount of MW's reserved for RFR, and the ramp rate in MW's per minute for determining ORS.

SHEET 5: Output

The output page is blocked in three areas. Each area takes one of the studies and presents the data in dollars per period. The conversion from total cost to periodic cost is done by multiplying the asset by the cost of capital input on the "Accounting Data" page.

The RS-VC block presents two different methods. The first is the vector analysis which is divided in to two sections. The "Modified Method" takes the values from the vector analysis page and applies the cost of capital to the asset costs to determine the periodic cost. The second cost "Share of Non-Generator Fixed Station Costs" is determined by multiplying the total of non-generator costs by the percent of losses associated with producing VARs times the cost of capital. The summation of the modified method and the share of non-generator costs equals the cost of producing RS-VC. The "Davis" method is identical to the first method with the exception that Mr. Davis includes the additional cost of producing voltage in the fixed cost of VARs.

The second method takes the cost of the generator from the accounting data page and applies the 1-PF method to the cost of the generator before applying the cost of capital to the assets. The total cost of VARs under method two includes the the share of non-generator fixed station costs as described above.

The "Regulation and Frequency Response Output Area" presents three pieces of information. The first piece gives the results of method one or the actual identified costs times the cost of capital. This result does not take capacity in to account. The second piece gives the results from the application of method two. Method two uses the unit cost times the percentage of MW available divided by the unit rating times the cost of capital. When this method is used the cost changes as the input of MW's available changes.

The "Operating Reserve - Spinning Output Area" presents three pieces of information. The first piece gives the results of method one or the actual identified costs times the cost of capital. This result does not take capacity in to account. The second piece gives the results from the application of method two. Method two uses the unit cost times the percentage of MW available divided by the unit rating times the cost of capital. When this method is used the cost changes as the input of MW's available changes.

6.1.1.1.2 Sheet 1 Accounting Data

On the next page, three separate input areas are shown. Each area requires data for the station, unit (not including the turbogenerator), and the turbogenerator. Area one is needed to account for those costs that are required for station operation. The shared costs will be prorated by turbine nameplate rating to the unit being studied. Area two is required to account for unit specific costs. Area three was separated from unit specific costs for VAr analysis. Area three requires a breakdown of the turbogenerator by turbine and controls, generator and controls (further division by stator and rotor), exciter and controls, and step-up transformer (if part of unit costs).

Power Station Name: NORTH AMERICAN FOSSIL

Unit ***8*** **Input Data Sheet For Financial Data**

Input areas are gray scaled.

COST ACCOUNTS FOR SHARED STATION RESOURCES: USE EITHER FERC OR ANOTHER METHOD					
ACCOUNT NAME	ACCOUNT #	COST	DEPRECIATION	NET VALUE	%
Land & Land Rights	**310**	**$275,224**	**$0**	$275,224	2.91%
Structures & Improvements	**311**	**8,189,296**	**0**	8,189,296	86.53%
Other		**1,000,000**	**0**	1,000,000	10.57%
				0	0.00%
				0	0.00%
				0	0.00%
				0	0.00%
				0	0.00%
				0	0.00%
				0	0.00%
				0	0.00%
				0	0.00%
				0	0.00%
				0	0.00%
				0	0.00%
	TOTAL	$9,464,520	$0	$9,464,520	100.00%

NON-TURBOGENERATOR COSTS/UNIT	8	RESOURCES: USE EITHER FERC OR ANOTHER METHOD			
ACCOUNT NAME	ACCOUNT #	COST	DEPRECIATION	NET VALUE	%
Boiler Unit Equipment	**312**	**63,199,050**		63,199,050	67.67%
Enginees	**313**	**0**		0	0.00%
Accessories	**315**	**8,455,264**		8,455,264	9.05%
Misc Equipment	**316**	**21,741,217**		21,741,217	23.28%
				0	0.00%
				0	0.00%
				0	0.00%
				0	0.00%
				0	0.00%
				0	0.00%
				0	0.00%
				0	0.00%
				0	0.00%
				0	0.00%
MISC.				0	0.00%
	TOTAL	$93,395,531	$0	$93,395,531	100.00%

TURBOGENERATOR COSTS FOR UNIT	8	USE EITHER FERC OR ANOTHER METHOD			
DESCRIPTION		ALLOCATED	DEPRECIATION	NET VALUE	%
TOTAL TURBOGENERATOR	**$50,242,732**	COSTS	VALUE OR %		
			0		
TURBINE & CONTROLS	**0.6000**	30,145,639		30,145,639	60.00%
GENERATOR STATOR & CONTROLS	**0.1600**	8,038,837		8,038,837	16.00%
GENERATOR ROTOR & CONTROLS	**0.1200**	6,029,128		6,029,128	12.00%
EXCITER & CONTROLS	**0.0900**	4,521,846		4,521,846	9.00%
STEP-UP TRANSFORMER	**0.0300**	1,507,282		1,507,282	3.00%
TOTAL	1.00	$50,242,732	$0	$50,242,732	100.00%

Sheet 1: Accounting Data Areas 1-3 (from top box to lower box)

Area 4 of sheet 1 requires that all turbine units within the station be identified by turbine nameplate rating. The total of the units is used to prorate shared station costs to the unit being studied. The box immediately to the right of the turbine ratings presents the total unit's fixed costs for allocation to ancillary services. Also located in area 4 is the required entry for the cost of capital that will be used for the estimate of period's fixed costs.

Power Station Name: NORTH AMERICAN FOSSIL

Unit ***8*** **Station Data and Results Sheet**

Input areas are gray scaled. ***Results below are include shared resources***

THIS SECTION IS USED FOR STATION DATA			OUTPUT FROM DATA USING STATION/UNIT COSTS AND PERCENTAGES	
				UNIT
UNIT	**MW**	PRORATED		8
NUMBERS	**RATINGS**	NET VALUES		TOTALS
1	**65**	$413,159	PRORATED SHARED RESOURCES	$1,589,073
2	**75**	$476,722	SPECIFIC NON-TURBOGEN ITEMS	$93,395,531
3	**130**	$826,318		
4	**116**	$737,330	STEAM TURBOGENERATOR (STG)	
5	**248**	$1,576,361	TURBINE & CONTROLS	$30,145,639
6	**258**	$1,639,924	GENERATOR STATOR & CONTROLS + STEP-UP XFO	$9,546,119
7	**347**	$2,205,634	GENERATOR ROTOR & CONTROLS	$6,029,128
8	**250**	$1,589,073	EXCITER & CONTROLS	$4,521,846
9		$0	SUBTOTAL STG	$50,242,732
10		$0		
TOTAL	1,489	$9,464,520	TOTAL UNIT	$145,227,336

COST OF CAPITAL PER PERIOD - % PER TIME PERIOD (e.g. % PER YEAR)	**10.00%**

Sheet 1: Accounting Data Area 4

6.1.1.1.3 Sheet 2: Generator Power Factors

This sheet stores the historic or user defined power factor (PF) number that will be used in determining the fixed cost of VAr's. At least one power factor must be entered on this sheet and selected as the PF Type.

Power Station Name: NORTH AMERICAN FOSSIL

Unit *8* GENERATOR POWER FACTORS (PF) - INPUT SHEET

LOAD THE PF DATA IN THE GRAY AREAS
POWER FACTOR = PF

		PF	PF TYPE
RATED PF	->	**0.8800**	1
USER DEFINED RATED PF	->	**0.9800**	2
AVERAGE QUARTERLY PF	->	0.8675	3
AVERAGE MONTHLY PF	->	0.8775	4
AVERAGE WEEKLY PF	->	0.8767	5
AVERAGE DAILY PF	->	0.8667	6
AVERAGE HOURLY PF	->	0.9638	7
ENTER THE POWER FACTOR TYPE TO BE USED			**1**

This page requires the entry and selection of PF(s) and PF TYPE

QUARTERLY PF'S

QTR	PF
1	**0.88**
2	**0.87**
3	**0.85**
4	**0.87**

MONTHLY PF'S

MONTH	PF
1	**0.85**
2	**0.86**
3	**0.87**
4	**0.88**
5	**0.87**
6	**0.87**
7	**0.88**
8	**0.91**
9	**0.9**
10	**0.89**

WEEKLY PF'S

WEEK	PF
1	**0.88**
2	**0.88**
3	**0.88**
4	**0.88**
5	**0.87**
6	**0.87**
7	
8	
9	
10	
11	
12	
13	
14	
15	
16	
17	
18	

DAILY PF'S

DAY	PF
1	**0.88**
2	**0.84**
3	**0.88**
4	
5	
6	
7	
8	
9	
10	
11	
12	
13	
14	
15	
16	
17	
18	

HOURLY PF'S

HOUR	PF
1	**0.98**
2	**0.981**
3	**0.9802**
4	**0.98**
5	**0.978**
6	**0.97**
7	**0.95**
8	**0.98**
9	**0.98**
10	**0.98**
11	**0.975**
12	**0.975**
13	**0.96**
14	**0.95**
15	**0.94**
16	**0.94**
17	**0.93**
18	**0.92**

Sheet 2: Generator Power Factors

6.1.1.1.4 Sheet 3: Vector Analysis

The user needs only to input the synchronous reactance value (Xd) in order to use the vector analysis method. However, if the user has determined the variable losses associated with producing VAr's and wants to enter the percent of loss associated with the production, then there is a cell location which will use the percentage in computing VAr costs.

Power Station Name: NORTH AMERICAN FOSSIL

Unit 8 VECTOR ANALYSIS FOR VARS

INPUTS	
POWER FACTOR	0.88
Xd	**1.69**

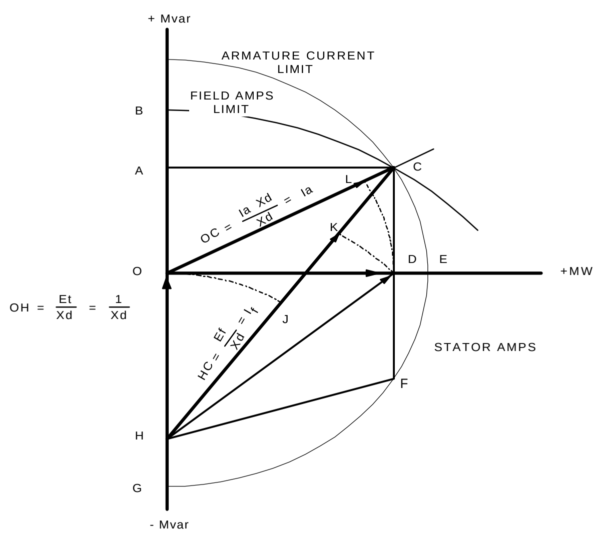
GENERATOR LOSSES ASSOCIATED WITH VAR PRODUCTION ACCORDING TO EPRI VARIABLE COST STUDY	
AS A % OF TURBINE RATING	**0.14%**

VECTOR MAGNITUDES			
OA	0.47	HJ	0.59
OC	1.00	HK	1.06
OD	0.88	HC	1.38
OH	0.59	JK	0.47
OL	0.88	KC	0.32
HD	1.06	LC	0.12
AC	0.88	AOC^{o}	28.36

DAVIS'	Developed by Murray Davis		
RESULTS:			
STATOR (ARMATURE)			
OL/OC	88.00%	WATTS	
LC/OC	12.00%	VAR	FOR RS-VC
ROTOR (FIELD)			
JK/HC	33.90%	WATT	
KC/HC	23.31%	VAR.	FOR RS-VC
HJ/HC	42.79%	VOLTAGE	FOR RS-VC

MODIFIED VECTOR ANALYSIS			Modified by Encotech
RESULTS:			
STATOR (ARMATURE)			
OL/OC	88.00%	WATTS	
LC/OC	12.00%	VAR	FOR RS-VC
ROTOR (FIELD)			
JK/HC	33.90%	WATTS	
KC/HC	23.31%	VAR	FOR RS-VC
HJ/HC	42.79%	VOLTAGE	FOR WATTS

Composite Generator Vector Allocation



Note: This graph is "typical", not for illustrating specific unit(s)

RESULTS FOR
ALLOCATION OF FIXED ASSETS FOR UNIT 8
FOR REACTIVE SUPPLY AND VOLTAGE CONTROL

	DAVIS	MODIFIED*
GENERATOR STATOR	$1,145,534	$1,145,534
GENERATOR ROTOR	6,974,642	2,459,867
COST OF EPRI LOSSES		175,182
TOTAL	$8,120,176	$3,780,584

* INCLUDES COST OF STEP-UP XFO WITH STATOR

Sheet 3: Vector Analysis

6.1.1.1.5 Sheet 4: RFR & ORS

Because of the similarity of these two capacity studies, both RFR and ORS are located on this sheet. There are three main areas on this sheet. The first area (beginning at cell A1) is the RFR costs from user input. The second area (beginning in cell R1) is the ORS costs from user input. The third area (beginning in cell I1) relies on machine design to estimate the fixed costs of RFR & ORS. Entries for ramp rates, and the mean load are required.

Power Station Name: NORTH AMERICAN FOSSIL
Unit ***8***

Regulation and Frequency Response - Input Area

METHOD ONE = IDENTIFICATION AND ALLOCATION OF COSTS FOR RFR			TOTAL COST
	Summary of data entered		$3,500,000
Input areas are gray scaled			
ACCOUNT TITLES	DEPRECIATED COSTS	PERCENTAGE ASSOCIATED WITH RFR	ESTIMATED COSTS OF RFR
TELEMETERING EQUIPMENT	**$10,000,000**	**35.00%**	$3,500,000
AGC EQUIPMENT			0
FAST CONTROL SYSTEMS			0
COORDINATED BOILER/TURBINE CONTROLS			0
RESERVIE COST TOTAL			0
			0
			0
			0
			0
			0

Sheet 4: Area 1 RFR

Power Station Name:NORTH AMERICAN FOSSIL
Unit ***8***

Operating Reserve Spinning - Input Area

METHOD ONE = IDENTIFICATION AND ALLOCATION OF COSTS FOR ORS			TOTAL COST
	Summary of data entered		$3,000,000
Input areas are gray scaled.			
ACCOUNT TITLES	DEPRECIATED COSTS	PERCENTAGE ASSOCIATED WITH ORS	ESTIMATED COSTS OF ORS
TELEMETERING EQUIPMENT	**$15,000,000**	**20.00%**	$3,000,000
AGC EQUIPMENT			0
FAST CONTROL SYSTEMS			0
COORDINATED BOILER/TURBINE CONTROLS			0
RESERVE COST TOTAL			0
			0
			0
			0

Sheet 4: Area 2 ORS

Power Station Name: NORTH AMERICAN FOSSIL

Unit ***8***

Input area and results area for estimating RFR and ORS

Input areas are gray scaled.

METHOD TWO = ALLOCATION BASED ON ENTIRE PLANT AND LOAD			
UNIT NUMBER		8	
UNIT COST		145,052,154	
UNIT MW RATING		250	MW
MEAN LOAD		**190**	MW
LOAD AVAILABLE FOR EITHER RFR OR ORS		60	MW
ARE YOU USING FULL RANGE OF RFR AREA? (Y OR N)		**N**	
ENTER RAMP RATE FOR RFR (IN MW) (DO NOT ENTER AMOUNT BELOW)		**0.0**	
ENTER CAPACITY REQUIRED (IN MW) FOR RFR (DO NOT ENTER AMT ABOVE)	**5**	5	MW
PRORATED COST OF UNIT BASED ON MW RESERVED FOR RFR		2,901,043	
RAMP RATE IN MW PER MINUTE FOR ORS		**3.0**	MW
CALCULATED LOAD FOR ORS (10XRAMP RATE)		30	MW
PRORATED COST OF UNIT BASED ON MW RESERVED FOR ORS		17,406,258	

Sheet 4: Area 3 RFR & ORS

6.1.1.1.6 Sheet 5: Output

This sheet displays the fixed costs on a yearly basis by multiplying the total fixed costs developed on other sheets by the cost of capital entered on the accounting data sheet. Represented on this sheet is the percentage of the yearly costs to the total costs for the unit.

Power Station Name: NORTH AMERICAN FOSSIL

RESULTS SHEET FOR:

Unit *8*

ALL RESULTS FROM PRIOR PAGES HAVE BEEN MULTIPLIED BY THE COST OF CAPITAL

REACTIVE SUPPLY AND VOLTAGE CONTROL OUTPUT AREA	
SELECTED UNIT POWER FACTOR	0.88
METHOD ONE = ONE MINUS POWER FACTOR	
UNIT COSTS PLUS STATION COSTS	$241,165
SHARE OF NON-GENERATOR FIXED COSTS	17,518
TOTAL FIXED COSTS OF VARs USING 1-PF METHOD	$258,683
METHOD TWO = VECTOR ANALYSIS	
MODIFIED METHOD (INCLUDES SHARE OF STEP-UP XFO) COSTS	$360,540
SHARE OF NON-GENERATOR FIXED COSTS	17,518
TOTAL FIXED COSTS OF VARs USING MODIFIED METHOD	$378,058
DAVIS METHOD (INCLUDES SHARE OF STEP-UP XFO) COSTS	$962,746
SHARE OF NON-GENERATOR FIXED COSTS	17,518
TOTAL FIXED COSTS OF VARs USING DAVIS METHOD	$980,264

PERCENTAGE OF YEARLY VAR COST BASED ON TOTAL UNIT ANNUAL COST

METHOD ONE	MODIFIED VECTOR	DAVIS' METHOD
1.78%	2.60%	6.75%

REGULATION AND FREQUENCY RESPONSE OUTPUT AREA	
METHOD ONE: IDENTIFIED EQUIPMENT COSTS X COST OF CAPITAL	$350,000
METHOD TWO: MEGAWATTS METHOD	
MEGAWATTS AVAILABLE FOR RFR	5.0
ANNUAL COST OF RFR	$290,104

PERCENTAGE OF YEARLY RFR COST BASED ON TOTAL UNIT ANNUAL COST

METHOD ONE	METHOD TWO
2.41%	2.00%

OPERATING RESERVE - SPINNING OUTPUT AREA	
METHOD ONE: IDENTIFIED EQUIPMENT COSTS X COST OF CAPITAL	$300,000
METHOD TWO: MEGAWATTS METHOD	
MEGAWATTS AVAILABLE FOR ORS	30.0
ANNUAL COST FOR ORS	$1,740,626

PERCENTAGE OF YEARLY ORS COST BASED ON TOTAL UNIT ANNUAL COST

METHOD ONE	METHOD TWO
2.07%	11.99%

Sheet 5: Output

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DEFINITION AND TERMS

	Dimension/Units
Shared Resources – Assets that are used for more than one unit at a station (e.g. building housing production units, land, and transmission yard).	$
Unit Specific Costs – Assets that can be identified as belong to the unit under study (e.g. boiler, pumps, and motors).	$
Turbogenerator Costs – The machinery that is directly associated with the turbine and generator (e.g. turbine, generator, exciter, controls, and cooling systems).	$
Nameplate Rating – The manufacturer's specifications as stated in guarantees.	MW
Total Unit Cost – The summation of all unit specific costs and prorated share of shared resource costs.	$
Contribution Margin – The difference between selling price and variable costs. The margin between the two gives the amount of money available for other costs and profit.	$

	Dimension/Units
Cost of Capital - The cost of capital is the rate of return a firm must earn if it is to meet the promises to, and expectations of, investors who now are contemplating purchase of its securities. If a corporation is to fulfill its objective of increasing the wealth of its owners, it needs to earn more than its cost of capital."	% Per Year
Power Factor - PF is the cosine of the phase shift between the voltage and current for a particular generator.	p.u.
Xd (Synchronous Reactance) - reciprocal of short circuit ratio SCR (per unit)	
RS-VC – Reactive Supply and Voltage Control – reactive power from generating resources is needed to support the transmission operations and to continuously adjust the transmission system voltage in response to system needs.[9]	
Ramp Rate – The amount of change of output that a turbine can handle within a specific time period.	MW/minute
Mean Load – The average production level of energy over a period of time	MW
RFR – Regulation and Frequency Response – maintains the schedule frequency at 60 Hz. [9]	MW
ORS – Operating Reserve Spinning – capacity "provided by power plants that are on- line and only partially loaded."[9]	MW

[9] "Cost of Providing Ancillary Services from Power Plants Volume 1: A Primer", D. Curtice, Electric Research Institute, Inc., 1997

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DISCUSSION AND CONCLUSIONS

Many factors posed a challenge in developing the methodologies for the fixed costs:

The ancillary services of Reactive Supply and Voltage Control, Regulation and Frequency Response, and Operating Reserve – Spinning are new "products" to be priced and sold separately from the traditional product of electric energy by Generators of electricity. These "products" are being produced in a highly integrated plant in which many major components are fully required for the production of each of the several "products". In the absence of past experience or common practice to refer to in determining the portion of fixed costs of a plant to be allocated to each service, what basis should be used for allocating the cost of a shared resource to several services?

The amount of service produced will likely vary through time, and therefore the amount of resources allocated to a service will vary with time. This posed the question of what time period to use in defining the fixed cost for each service. Should there be a fixed cost for each service for example for every hour of the year, or would a time average cost for an entire year be preferable?

The fixed cost of each of the three services is likely to be modest so the methodology must not be too demanding and require data that is difficult and costly to obtain.

The methodologies are based on the following broad principles.

The allocation of a fixed cost to a certain service shall be based on "cause and effect", that is there shall be a physical or engineering principle underlying the allocation of a fixed cost. For example, the synchronous generator can be said to produce three "products": real electric power (MW), reactive power (MVAr), and voltage control (V), the latter two being classified as an ancillary service. The methodology for this service is based on electrical system analysis of the currents flowing in the generator to produce these products and services.

The time period for the fixed cost of each service was chosen to be one year, because that is the common accounting period and also the period for which financial data and production records or schedules are most likely to be available. Because each service is likely to be provided in varying quantity throughout a year, "time averaging" is provided for by allowing input of production data or schedules down to a resolution of once per hour, i.e. up to 8760 points per year, although such fine subdivision is not recommended and is unlikely to be justified. It is left to the user to judge the degree of subdivision to use based on the accuracy desired and the data and effort available.

To manage and speed up the detailed calculations, all methodologies have been programmed into spreadsheets with clearly marked input fields and indication of choices or defaults. A few test calculations have been performed with real data from participating utilities. These results suggest that the resolution, accuracy and effort required are reasonable considering the effect of the fixed cost on the total cost of the services. Preliminary results suggests the following:

- The fixed cost of RS-VC was found to be of the order of 1 to 5% of total plant/unit annual fixed cost, depending on PF and method used.
- The fixed cost of RFR was found to be of the order of 2% of the total plant/unit annual fixed costs for every 5 MW's of bandwidth.
- The fixed cost of ORS was found to be of the order of 4% of the total plant/unit annual fixed costs for every 10 MW's of capacity.

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REFERENCES

1. FERC Order 888. Washington, D.C. April 24, 1996

2. Defining Interconnected Operations Services Under Open Access. IOS Working Group; EPRI Report TR-108097, 5152-01, Final Report, May 1997.

3. Policy 10 Interconnected Operations Services. IOS-ITF, Draft Report, April 7, 1998.

4. Cost of Providing Ancillary Services from Power Plants, Volume 1: A Primer. Report: EPRI TR-107270-V1, Final Report, March 1997

5. Cost of Providing Ancillary Services from Power Plants, Volume 2: Regulation and Frequency Response. Report: EPRI TR-107270-V2, Final Report, April 1997

6. Cost of Providing Ancillary Services from Power Plants, Volume 3: Reactive Supply and Voltage Control. Report: EPRI TR-107270-V3, Final Report, June 1997

7. Cost of Providing Ancillary Services from Power Plants, Volume 4: Operating Reserve-Spinning. Report: EPRI TR-107270-V4, Final Report, July 1997

8. Compendium to: Ancillary Services Workshop. Measurement and Costing of Ancillary Services in Emerging Market Structures. Sponsored by EPRI, EEI, NERC, APPA, NRECA, EPSA, CEA. December 10-11, 1997. Miami, Florida.

9. United States of America before the Federal Energy Regulatory Commission. The Detroit Edison Company: Docket No. OA96-78-000. Direct Testimony of Murray W. Davis.

A

APPENDIX

Vector Allocation Method for Determining Reactive Supply and Voltage Control Costs, and Modifications thereto

The following summary is based on "Direct Testimony of Murray W. Davis" before The Federal Energy Regulatory Commission, Docket No. OA96-78-000 (Ref. 9) and presentation at EPRI Ancillary Services Workshop, Miami, Fl, Dec. 10-11, 1997, (Ref. 8).

The Vector Allocation Method uses the vectorial representation of stator and rotor currents in a synchronous generator to allocate the capital cost of the generator to the functions of supplying:

1. voltage (Volts)
2. real power, (MW), and
3. reactive power (MVAr)

The method determines the percentage of capital cost of the stator system and rotor system that may be allocated to outputs 1-3 above, assuming that the relative magnitude of the currents required for these three outputs is a fair representation of the relative capital costs of the equipment engaged in producing these outputs. This is based on the further assumption, that the cost of a synchronous generator is proportional its MVA rating which is a function of the following capabilities:

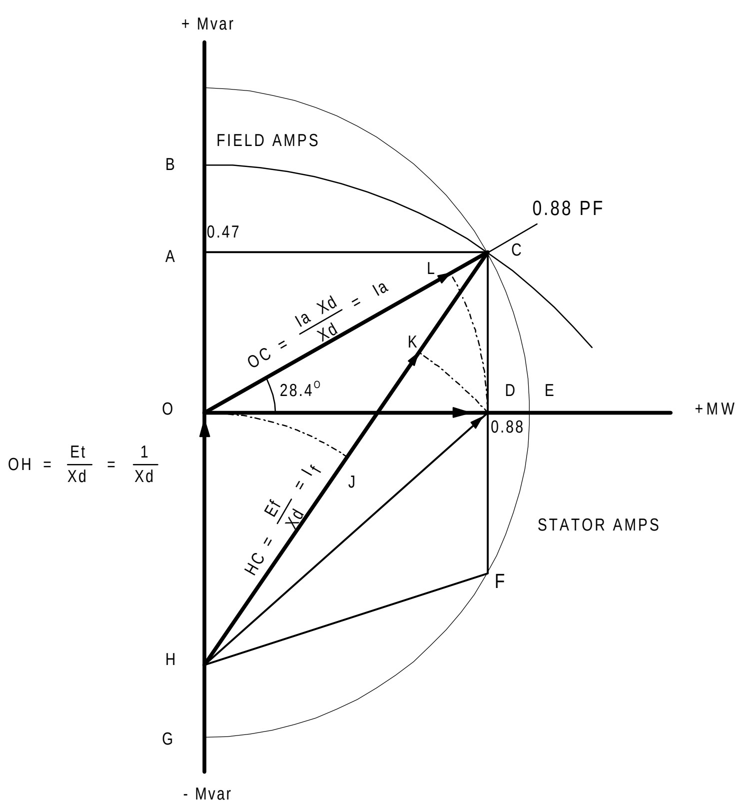
- Armature current (stator) heating limit
- Field current (rotor) heating limit
- Stability limit (short circuit ratio, SCR)

The basic current vector diagram for a synchronous generator is shown in Figure A-1 where kiloWatts are plotted on the abscissa (in per unit of rated capacity) and kiloVArs are plotted on the ordinate, (also in per unit of rated capacity). This is a simplification of the generator capacity diagram that may be found in most generator instruction books supplied by the OEM.

In the example of Figure A-1, the rated operating point C is shown to be at PF=0.88. Point C is where the armature current limit and field current limit intersect. The vector OC represents the total armature (stator bar) current I_a. The projection of this current onto the horizontal axis, vector OD, represents the current that produces real power. Vector DC represents the reactive portion of I_a. It can be seen that the maximum real power, which this generator can produce is the PF (0.88) times its MVA rating.

In Figure A-1, vector HO represents the field current (in per unit) required to produce rated voltage at no load (operating point at O). The magnitude of this vector is $1/\chi_d$ = SCR (short circuit ratio, in this case selected to be 0.59). To reach the operating point C it has been necessary to increase the field current to magnitude and direction of vector HC. This illustrates that the SCR, which has a major influence on the stability of the generator operation, has a significant influence on the field current required, because the longer the vector HO, the longer will be the field current I_f (vector HC). And the greater the field current at the rating point, the costlier the field and excitation system will be.

Composite Generator Vector Allocation



COMPOSITE UNIT 11,067 MVA, PF = 0.88 Xd= 1.69	
I_a allocation	I_f allocation
OL /OC = 88%	JK / HC = 34%
LC /OC = 12%	KC / HC = 23%
	HJ / HC = 43%
100%	100%

VECTOR MAGNITUDES	
OA = 0.47	HJ = 0.59
OC = 1.00	HK = 1.06
OD = 0.88	HC = 1.38
OH = 0.59	JK = 0.47
OL = 0.88	KC = 0.32
HD = 1.06	LC = 0.12

OL: I_a allocation to watt generation
LC: I_a allocation to var generation
HJ: I_f allocation to voltage generation
JK: I_f allocation to watt generation
KC: I_f allocation to var generation

Figure A-1
Composite Generator Phasor Diagram

The magnitude of I_f (vector HC) is calculated in the box on Figure A-1 using the right angled triangle HAC whose base and side are determined by the PF and SCR. Once the magnitude of vector HC is known, the maximum kVAr possible with this generator (vector OB) can be found.

The basic principles of Figure A-1 can now be applied to the performance of the rotor and stator systems of a synchronous generator as shown in Figure A-2. From this will come a rationale for the percentages of the capital costs of these systems to be allocated to the RS-VC service.

In Figure A-2, point C is the operating point for which the fixed cost analysis is to be performed, normally rated capacity. Vector OC represents the total armature current I_a. Vector OD is that part of this current which produces real power. Vector OL is of the same magnitude of OD "turned on" to vector OC. Hence the fraction OL/OC is the portion (88% in the example) of I_a that produces real power and is the fraction of the total stator system fixed cost to be allocated to real power, or Watts, supply. The remainder of I_a, i.e. vector LC is the portion of the armature current that produces reactive power. Hence the fraction LC/OC is the portion (12% in the example) of the total stator system fixed cost to be allocated to VAr supply. (Note that for the stator, this allocation is the same as by the "one minus power factor" method).

Vector HC in Figure A-2 represents the total field current I_f. Vector HO is the field current required to produce rated voltage at no load. Vector HJ is the magnitude of vector HO "turned on" to vector HC. Hence the fraction HJ/HC is the portion (43% in the example) of I_f required to produce rated voltage and constitutes the portion of the total rotor system fixed cost to be allocated to Voltage supply.

Vector HD is the field current required to produce rated power (Watts) at power factor 1.0 (i.e. with operating point at D). Vector HK is the magnitude of Vector HD "turned on" to vector HC. Hence the difference between HK and HJ, of magnitude JK, is the portion of I_f required to produce the real power, and the fraction JK/HC is the portion (34% in the example) of the total rotor system fixed cost to be allocated to Watts supply.

Having accounted for the portions of I_f required for Volts and Watts, the remainder of I_f, vector KC, is the portion required for VAr supply. Hence the fraction KC/HC is the portion (23% in the example) of the total fixed cost of the rotor system to be allocated to VAr supply.

In Mr. Davis' testimony the above allocations are summed up as follows:

Fixed cost for Watts supply = OL/OC*(cost of stator)+JK/HC*(cost of rotor)

and

Fixed cost for Reactive Supply and Voltage Control = LC/OC*(cost of stator)+
(HJ+KC)/HC*(cost of rotor)

In this definition Mr. Davis interprets "Voltage Control" to mean voltage supply because the vector HJ (required for rated voltage at no load) is included with the VC-RS service. The authors believe that a more rational allocation would be to include the cost HJ/HC*(cost of rotor) with the Watts production, because rated voltage is required to produce any output, and achieving rated voltage does not even begin to control the voltage. Thus we recommend the following definition:

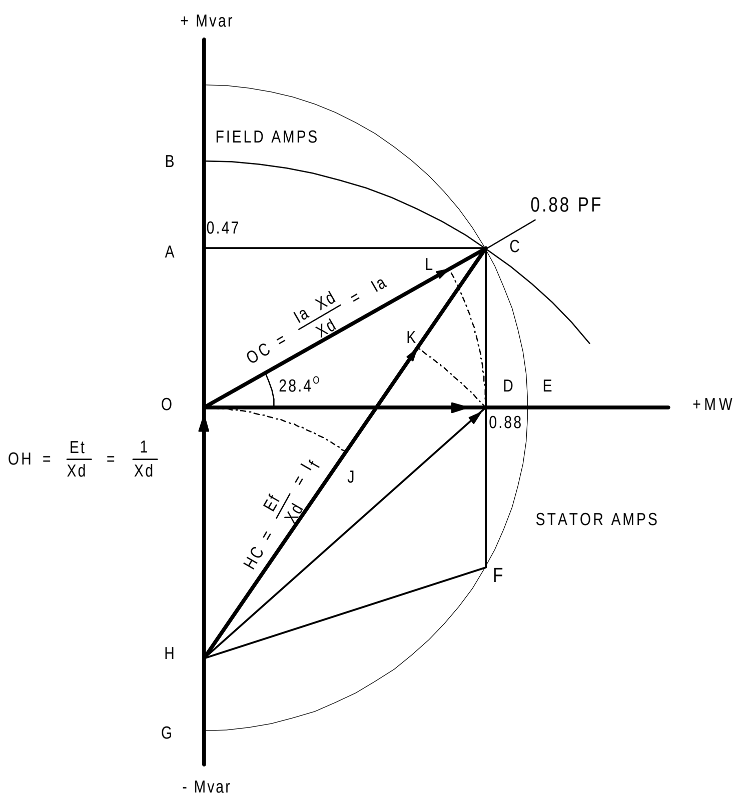
Fixed cost for <u>Watts and Voltage Supply</u> = OL/OC*(cost of stator)+[HJ+JK]/HC*(cost of rotor)

and

Fixed cost for <u>Reactive Supply and Voltage Control</u> = LC/OC*(cost of stator)+
(KC)/HC*(cost of rotor)

The implementation in spreadsheet format is set up to allow a choice of Davis' allocation or the modified allocation labeled "Encotech".

Composite Generator Vector Allocation



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100%	100%

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OD = 0.88	HC = 1.38
OH = 0.59	JK = 0.47
OL = 0.88	KC = 0.32
HD = 1.06	LC = 0.12

OL:	I_a allocation to watt generation
LC:	I_a allocation to var generation
HJ:	I_f allocation to voltage generation
JK:	I_f allocation to watt generation
KC:	I_f allocation to var generation

Figure A-2
Composite Generator Vector Allocation