WIND TURBINE CONNECTED TO THE ELECTRICAL NETWORK

He brings forth the wind from His storehouses. Psalms 135:7

Only a few hardy people in the United States live where 60 Hz utility power is not readily available. The rest of us have grown accustomed to this type of power. The utility supplies us reliable power when we need it, and also maintains the transmission and distribution lines and the other equipment necessary to supply us power. The economies of scale, diversity of loads, and other advantages make it most desirable for us to remain connected to the utility lines. The utility is expected to provide high quality electrical power, with the frequency at 60 Hz and the harmonics held to a low level. If the utility uses wind turbines for a part of its generation, the output power of these turbines must have the same high quality when it enters the utility lines. There are a number of methods of producing this synchronous power from a wind turbine and coupling it into the power network. Several of these will be considered in this chapter.

Many applications do not require such high quality electricity. Space heating, water heating, and many motor loads can be operated quite satisfactorily from dc or variable frequency ac. Such lower quality power may be produced with a less expensive wind turbine so that the unit cost of electrical energy may be lower. The features of such machines will be examined in the next chapter.

1 METHODS OF GENERATING SYNCHRONOUS POWER

There are a number of ways to get a constant frequency, constant voltage output from a wind electric system. Each has its advantages and disadvantages and each should be considered in the design stage of a new wind turbine system. Some methods can be eliminated quickly for economic reasons, but there may be several that would be competitive for a given application. The fact that one or two methods are most commonly used does not mean that the others are uncompetitive in all situations. We shall, therefore, look at several of the methods of producing a constant voltage, constant frequency electrical output from a wind turbine.

Eight methods of generating synchronous power are shown in Table 5.1. The table applies specifically to a two or three bladed horizontal axis propeller type turbine, and not all the methods would apply to other types of turbines[4]. In each case the output of the wind energy collection system is in parallel or in synchronism with the utility system. The ac or synchronous generator, commonly used on larger wind turbines, may be replaced with an induction generator in most cases. The features of both the ac and induction generators will be considered later in this chapter.

Systems 1,2, and 3 are all constant speed systems, which differ only in pitch control and gearbox details. A variable pitch turbine is able to operate at a good coefficient of performance over a range of wind speeds when turbine angular velocity is fixed. This means that the average power density output will be higher for a variable pitch turbine than for a fixed pitch machine. The main problem is that a variable pitch turbine is more expensive than a fixed pitch turbine, so a careful study needs to be made to determine if the cost per unit of energy is lower with the more expensive system. The variable pitch turbine with a two speed gearbox is able to operate at a high coefficient of performance over an even wider range of wind speeds than system 1. Again, the average power density will be higher at the expense of a more expensive system.

TABLE 5.1 Eight methods of generating synchronous electrical power.

Rotor	Transmission	Generator
1. Variable pitch, constant speed	Fixed-ratio gear	ac generator
2. Variable pitch, constant speed	Two-speed-ratio gear	ac generator
3. Fixed pitch, constant speed	Fixed-ratio-gear	ac generator
4. Fixed pitch, variable speed	Fixed-ratio gear	dc generator/ dc motor/ac generator
5. Fixed pitch, variable speed	Fixed-ratio gear	ac generator/rectifier/ dc motor/ac generator
6. Fixed pitch, variable speed	Fixed-ratio gear	ac generator/rectifier/inverter
7. Fixed pitch, variable speed	Fixed-ratio gear	field-modulated generator
8. Fixed pitch,	Variable-ratio	ac generator

Systems 4 through 8 of Table 5.1 are all variable speed systems and accomplish fixed frequency output by one of five methods. In system 4, the turbine drives a dc generator which drives a dc motor at synchronous speed by adjusting the field current of the motor. The dc motor is mechanically coupled to an ac generator which supplies 60 Hz power to the line. The fixed pitch turbine can be operated at its maximum coefficient of performance over the entire wind speed range between cut-in and rated because of the variable turbine speed. The average power output of the turbine is high for relatively inexpensive fixed pitch blades.

The disadvantage of system 4 over system 3 is the requirement of two additional electrical machines, which increases the cost. A dc machine of a given power rating is larger and more complicated than an ac machine of the same rating, hence costs approximately twice as much. A dc machine also requires more maintenance because of the brushes and commutator. Wind turbines tend to be located in relatively hostile environments with blowing sand or salt spray so any machine with such a potential weakness needs to be evaluated carefully before installation.

Efficiency and cost considerations make system 4 rather uncompetitive for turbine ratings below about 100 kW. Above the 100-kW rating, however, the two dc machines have reasonably good efficiency (about 0.92 each) and may add only ten or fifteen percent to the overall cost of the wind electric system. A careful analysis may show it to be quite competitive with the constant speed systems in the larger sizes.

System 5 is very similar to system 4 except that an ac generator and a three-phase rectifier is used to produce direct current. The ac generator-rectifier combination may be less expensive than the dc generator it replaces and may also be more reliable. This is very important on all equipment located on top of the tower because maintenance can be very difficult there. The dc motor and ac generator can be located at ground level in a more sheltered environment, so the single dc machine is not quite so critical.

System 6 converts the wind turbine output into direct current by an ac generator and a solid state rectifier. A dc generator could also be used. The direct current is then converted to 60 Hz alternating current by an inverter. Modern solid state inverters which became available in the mid 1970's allowed this system to be one of the first to supply synchronous power from the wind to the utility grid. The wind turbine generator typically used was an old dc system such as the Jacobs or Wincharger. Sophisticated inverters can supply 120 volt, 60 Hz electricity for a wide range of input dc voltages. The frequency of inverter operation is normally determined by the power line frequency, so when the power line is disconnected from the utility, the inverter does not operate. More expensive inverters capable of independent operation are also used in some applications.

System 7 uses a special electrical generator which delivers a fixed frequency output for variable shaft speed by modulating the field of the generator. One such machine of this type is the field modulated generator developed at Oklahoma State University[7]. The electronics necessary to accomplish this task are rather expensive, so this system is not necessarily less expensive than system 4, 5, or 6. The field modulated generator will be discussed in the next chapter.

System 8 produces 60 Hz electricity from a standard ac generator by using a variable speed transmission. Variable speed can be accomplished by a hydraulic pump driving a hydraulic motor, by a variable pulley vee-belt drive, or by other techniques. Both cost and efficiency tend to be problems on variable ratio transmissions.

Over the years, system 1 has been the preferred technique for large systems. The Smith-Putnam machine, rated at 1250 kW, was of this type. The NASA-DOE horizontal axis propeller machines are of this type, except for the MOD-5A, which is a type 2 machine. This system is reasonably simple and enjoys largely proven technology. Another modern exception to this trend of using system 1 machines is the 2000 kW machine built at Tvind, Denmark, and completed in 1978. It is basically a system 6 machine except that variable pitch is used above the rated wind speed to keep the maximum rotational speed at a safe value.

The list in Table 5.1 illustrates one difficulty in designing a wind electric system in that many options are available. Some components represent a very mature technology and well defined prices. Others are still in an early stage of development with poorly defined prices. It is conceivable that any of the eight systems could prove to be superior to the others with the right development effort. An open mind and a willingness to examine new alternatives is an important attribute here.

2 AC CIRCUITS

It is presumed that readers of this text have had at least one course in electrical theory, including the topics of electrical circuits and electrical machines. Experience has shown, however, that even students with excellent backgrounds need a review in the subject of ac circuits. Those with a good background can read quickly through this section, while those with a poorer background will hopefully find enough basic concepts to be able to cope with the remaining material in this chapter and the next.

Except for dc machines, the person involved with wind electric generators will almost always be dealing with sinusoidal voltages and currents. The frequency will usually be 60 Hz and operation will usually be in steady state rather than in a transient condition. The analysis of electrical circuits for voltages, currents, and powers in the steady state mode is very commonly required. In this analysis, time varying voltages and currents are typically represented by equivalent complex numbers, called phasors, which do not vary with time. This reduces the problem solving difficulty from that of solving differential equations to that of solving algebraic equations. Such solutions are easier to obtain, but we need to remember that they apply only in the steady state condition. Transients still need to be analyzed in terms of the circuit differential equation.

A complex number z is represented in *rectangular form* as

$$z = x + jy \tag{1}$$

where x is the real part of z, y is the imaginary part of z, and $j = \sqrt{-1}$. We do not normally give a complex number any special notation to distinguish it from a real number so the reader will have to decide from the context which it is. The complex number can be represented by a point on the complex plane, with x measured parallel to the real axis and y to the imaginary axis, as shown in Fig. 1.

The complex number can also be represented in *polar form* as

$$z = |z|\angle\theta \tag{2}$$

where the magnitude of z is

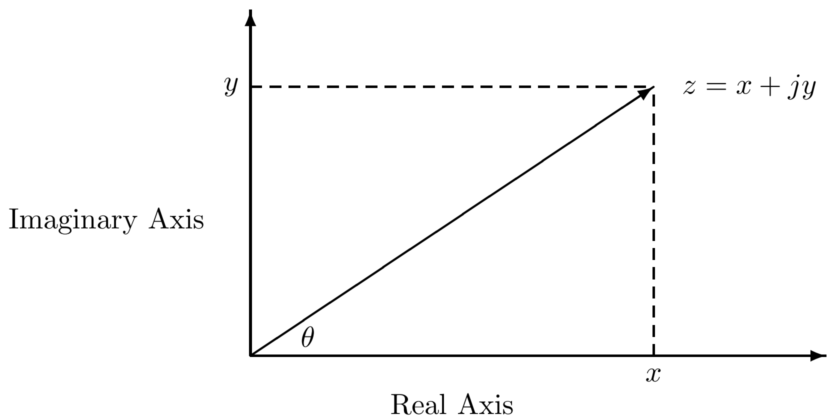

Figure 1: Complex number on the complex plane.

$$|z| = \sqrt{x^2 + y^2} \tag{3}$$

and the angle is

$$\theta = \tan^{-1} \frac{y}{x} \tag{4}$$

The angle is measured counterclockwise from the positive real axis, being 90^o on the positive imaginary axis, 180^o on the negative real axis, 270^o on the negative imaginary axis, and so on. The arctan function covers only 180^o so a sketch needs to be made of x and y in each case and 180^o added to or subtracted from the value of θ determined in Eq. 4 as necessary to get the correct angle.

We might also note that a complex number located on a complex plane is different from a *vector* which shows direction in real space. Balloon flight in Chapter 3 was described by a vector, with no complex numbers involved. Impedance will be described by a complex number, with no direction in space involved. The distinction becomes important when a given quantity has both properties. It is shown in books on electromagnetic theory that a time varying electric field is a phasor-vector. That is, it has three vector components showing direction in space, with each component being written as a complex number. Fortunately, we will not need to examine any phasor-vectors in this text.

A number of hand calculators have the capability to go directly between Eqs. 1 and 2 by pushing only one or two buttons. These calculators will normally display the full 360^o variation in θ directly, saving the need to make a sketch. Such a calculator will be an important asset in these two chapters. Calculations are much easier, and far fewer errors are made.

Addition and subtraction of complex numbers are performed in the rectangular form.

$$z_1 + z_2 = x_1 + jy_1 + x_2 + jy_2 = (x_1 + x_2) + j(y_1 + y_2) \tag{5}$$

Multiplication and division of complex numbers are performed in the polar form:

$$z_1 z_2 = |z_1||z_2|\underline{/\theta_1 + \theta_2} \tag{6}$$

$$\frac{z_1}{z_2} = \frac{|z_1|}{|z_2|}\underline{/\theta_1 - \theta_2} \tag{7}$$

The impedance of the series RLC circuit shown in Fig. 2 is the complex number

$$Z = R + j\omega L - \frac{j}{\omega C} = |Z|\angle\theta \qquad \Omega \tag{8}$$

where $\omega = 2\pi f$ is the angular frequency in rad/s, R is the resistance in ohms, L is the inductance in henrys, and C is the capacitance in farads.

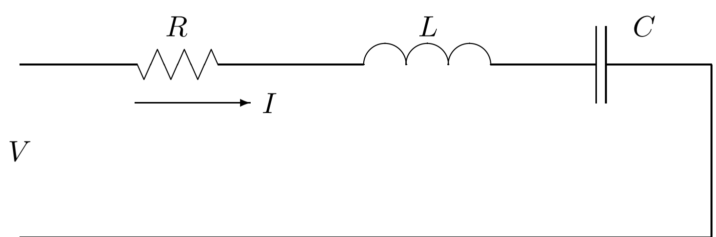

Figure 2: Series RLC circuit.

We define the reactances of the inductance and capacitance as

$$X_L = \omega L \qquad \Omega \tag{9}$$

$$X_C = \frac{1}{\omega C} \qquad \Omega \tag{10}$$

Reactances are always real numbers. The impedance of an inductor, $Z = jX_L$, is imaginary, but X_L itself (and X_C) is real and positive.

When a phasor root-mean-square voltage (rms) $V = |V|\angle\theta$ is applied to an impedance, the resulting phasor rms current is

$$I = \frac{V}{Z} = \frac{|V|}{|Z|}\underline{/-\theta} \qquad \text{A} \tag{11}$$

Example

The RL circuit shown in Fig. 3 has $R = 6\ \Omega$, $X_L = 8\ \Omega$, and $V = 200\underline{/0^o}$. What is the current?

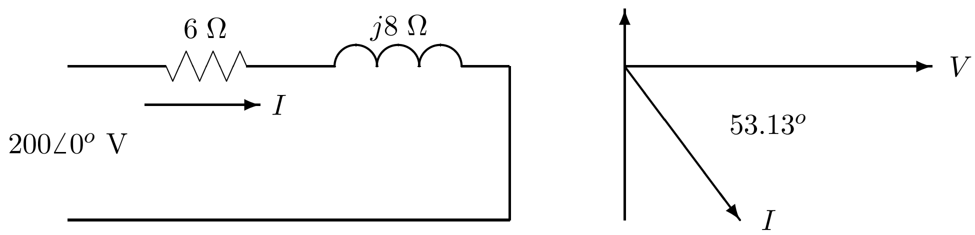

Figure 3: Series RL Circuit.

First we find the impedance Z.

$$Z = R + jX_L = 6 + j8 = 10\underline{/53.13^o}$$

The current is then

$$I = \frac{200\underline{/0^o}}{10\underline{/53.13^o}} = 20\underline{/-53.13^o}$$

A sketch of V and I on the complex plane for this example is also shown in Fig. 3. This sketch is called a *phasor diagram*. The current in this inductive circuit is said to *lag V*. In a capacitive circuit the current will *lead V*. The words "lead" and "lag" always apply to the relationship of the current to the voltage. The phrase "ELI the ICE man" is sometimes used to help beginning students remember these fundamental relationships. The word ELI has the middle letter L (inductance) with E (voltage) before, and I (current) after or lagging the voltage. The word ICE has the middle letter C (capacitance) with E after, and I before or leading the voltage in a capacitive circuit.

In addition to the voltage, current, and impedance of a circuit, we are also interested in the power. There are three types of power which are considered in ac circuits, the complex power S, the real power P, and the reactive power Q. The relationship among these quantities is

$$S = P + jQ = |S|\angle\theta \qquad \text{VA} \tag{12}$$

The magnitude of the complex power, called the *volt-amperes* or the *apparent* power of the circuit is defined as

$$|S| = |V||I| \qquad \text{VA} \tag{13}$$

The *real* power is defined as

$$P = |V||I| \cos\theta \qquad \text{W} \tag{14}$$

The *reactive* power is defined as

$$Q = |V||I| \sin\theta \qquad \text{var} \tag{15}$$

The angle θ is the difference between the angle of voltage and the angle of current.

$$\theta = \underline{/V} - \underline{/I} \qquad \text{rad} \tag{16}$$

The power factor is defined as

$$pf = \cos\theta = \cos\left(\tan^{-1}\frac{Q}{P}\right) \tag{17}$$

The real power supplied to a resistor is

$$P = VI = I^2R = \frac{V^2}{R} \qquad \text{W} \tag{18}$$

where V and I are the voltage across and the current through the resistor.

The magnitude of the reactive power supplied to a reactance is

$$|Q| = VI = I^2X = \frac{V^2}{X} \qquad \text{var} \tag{19}$$

where V and I are the voltage across and the current through the reactance. Q will be positive to an inductor and negative to a capacitor. The units of reactive power are volt-amperes reactive or vars.

Example

A series RLC circuit, shown in Fig. 4, has $R = 4\ \Omega$, $X_L = 8\ \Omega$, and $X_C = 11\ \Omega$. Find the current, complex power, real power, and reactive power delivered to the circuit for an applied voltage of 100 V. What is the power factor?

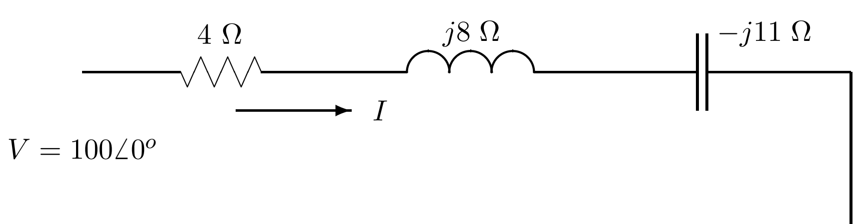

Figure 4: Series RLC circuit.

The impedance is

$$Z = R + jX_L - jX_C = 4 + j8 - j11 = 4 - j3 = 5\underline{/-36.87^o} \;\; \Omega$$

Assuming $V = |V|\underline{/0^o}$ is the reference voltage, the current is

$$I = \frac{V}{Z} = \frac{100\underline{/0^o}}{5\underline{/-36.87^o}} = 20\underline{/36.87^o} \;\; \mathrm{A}$$

The complex power is

$$S = |V||I|\angle\theta = (100)(20)\underline{/-36.87^o} = 2000\underline{/-36.87^o} \;\; \mathrm{VA}$$

The real power supplied to the circuit is just the real power absorbed by the resistor, since reactances do not absorb real power.

$$P = I^2 R = (20)^2(4) = 1600 \;\; \mathrm{W}$$

It is also given by

$$P = |V||I|\cos\theta = 100(20)\cos\underline{/36.87^o} = 1600 \;\; \mathrm{W}$$

The reactive power supplied to the inductor is

$$Q_L = I^2 X_L = (20)^2(8) = 3200 \;\; \mathrm{var}$$

The reactive power supplied to the capacitor is

$$Q_C = -I^2 X_C = -(20)^2(11) = -4400 \;\; \mathrm{var}$$

The net reactive power supplied to the circuit is

$$Q = Q_L + Q_C = 3200 - 4400 = -1200 \;\; \mathrm{var}$$

It is also given by

$$Q = |V||I|\sin\theta = 100(20)\sin(-36.87^o) = -1200 \;\; \mathrm{var}$$

The power factor is

$$\mathrm{pf} = \cos\theta = \cos(-36.87^o) = 0.8 \;\; \mathrm{lead}$$

The word "lead" indicates that θ is negative, or that the current is leading the voltage.

We see that the real and reactive powers can be found either from the input voltage and current or from the summation of the component real and reactive powers within the circuit.

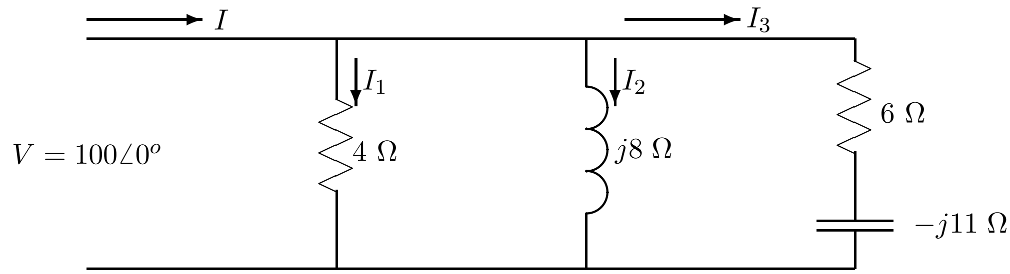

Figure 5: Parallel *RLC* circuit.

The effort required may be smaller or greater for one approach as compared to the other, depending on the structure of the circuit. The student should consider the relative difficulty of both techniques before solving the problem, to minimize the total effort.

Example

Find the apparent power and power factor of the circuit in Fig. 5.

One solution technique is to first find the input impedance.

$$\begin{aligned} Z &= \frac{1}{1/4 + 1/j8 + 1/(6 - j11)} = \frac{1}{0.25 - j0.125 + 1/(12.53\underline{/-61.39^o})} \\ &= \frac{1}{0.25 - j0.125 + 0.080\underline{/61.39^o}} = \frac{1}{0.25 - j0.125 + 0.038 + j0.070} \\ &= \frac{1}{0.288 - j0.055} = \frac{1}{0.293\underline{/-10.79^o}} = 3.41\underline{/10.79^o} \ \ \Omega \end{aligned}$$

The input current is then

$$I = \frac{V}{Z} = \frac{100\underline{/0^o}}{3.41\underline{/10.79^o}} = 29.33\underline{/-10.79^o} \ \ \text{A}$$

The apparent power is

$$|S| = |V||I| = 100(29.33) = 2933 \ \ \text{VA}$$

The power factor is

$$\text{pf} = \cos\theta = \cos 10.79^o = 0.982 \ \ \text{lag}$$

Another solution technique is to find the individual component powers. We have to find the current I_3 to find the real and reactive powers supplied to that branch.

$$I_3 = \frac{V}{6 - j11} = \frac{100\underline{/0^o}}{12.53\underline{/-61.39^o}} = 7.98\underline{/61.39^o}$$

The capacitive reactive power is then

$$Q_C = -|I_3|^2 X_C = -(7.98)^2(11) = -700 \text{ var}$$

The inductive reactive power is

$$Q_L = \frac{V^2}{X_L} = \frac{(100)^2}{8} = 1250 \text{ var}$$

The real power supplied to the circuit is

$$P = \frac{V^2}{4} + |I_3|^2(6) = \frac{(100)^2}{4} + (7.98)^2(6) = 2500 + 382 = 2882 \text{ W}$$

The complex power is then

$$S = P + jQ = 2882 + j1250 - j700 = 2882 + j550 = 2934\underline{/10.80^o} \text{ var}$$

so the apparent power is 2934 var and the power factor is

$$\text{pf} = \cos \underline{/10.80^o} = 0.982 \text{ lag}$$

The total effort by a person proficient in complex arithmetic may be about the same for either approach. A beginner is more likely to get the correct result from the second approach, however, because it reduces the required complex arithmetic by not requiring the determination of the input impedance.

We now turn our attention to three-phase circuits. We are normally interested in a balanced set of voltages connected in wye as shown in Fig. 6. If we select E_a, the voltage of point a with respect to the neutral point n, as the reference, then

$$\begin{aligned} E_a &= |E_a|\underline{/0^o} \quad \text{V} \\ E_b &= |E_a|\underline{/-120^o} \quad \text{V} \\ E_c &= |E_a|\underline{/-240^o} \quad \text{V} \end{aligned} \tag{20}$$

This set of voltages is said to form an *abc sequence*, since E_b lags E_a by 120^o, and E_c lags E_b by 120^o. We use the symbol E rather than V to indicate that we have a source voltage.

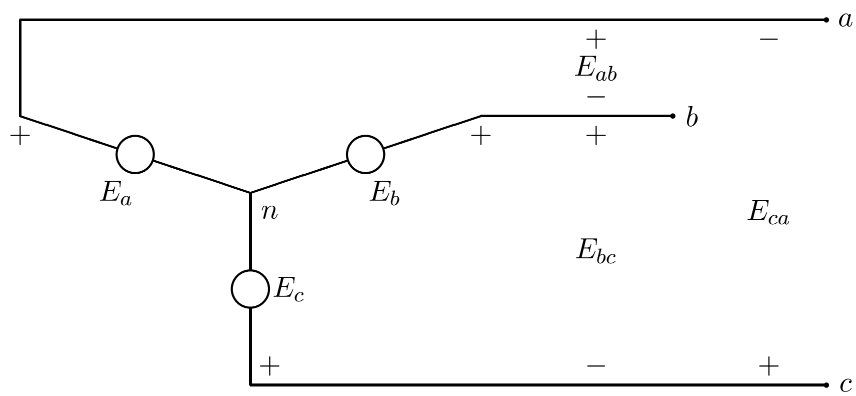

Figure 6: Balanced three-phase source.

The symbol V will be used for other types of voltages in the circuit. This will become more evident after a few examples.

The line to line voltage E_{ab} is given by

$$
\begin{aligned}
E_{ab} &= E_a - E_b = |E_a|(1\underline{/0^o} - 1\underline{/-120^o}) \\
&= |E_a|[1-(-0.5-j0.866)] = |Ea|(1.5+j0.866) \\
&= |Ea|\sqrt{3}\underline{/30^o} \qquad \text{V} \qquad (21)
\end{aligned}
$$

In a similar fashion,

$$
\begin{aligned}
E_{bc} &= \sqrt{3}|E_a|\underline{/-90^o} \qquad \text{V} \\
E_{ca} &= \sqrt{3}|Ea|\underline{/-210^o} \qquad \text{V} \qquad (22)
\end{aligned}
$$

These voltages are shown in the phasor diagram of Fig. 7.

When this three-phase source is connected to a balanced three-phase wye-connected load, we have the circuit shown in Fig. 8.

The current I_a is given by

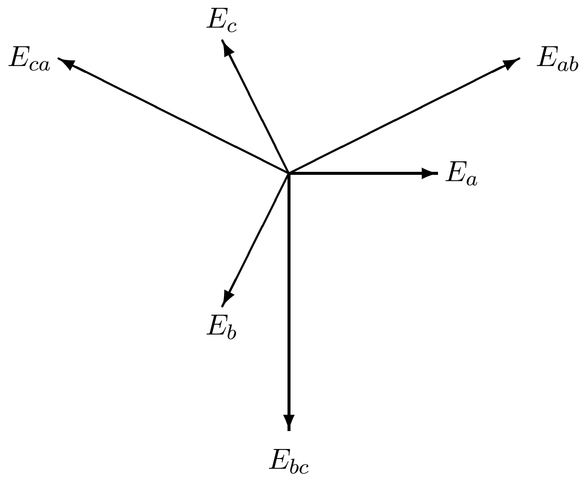

Figure 7: Balanced three-phase voltages for circuit in Fig. 5.6.

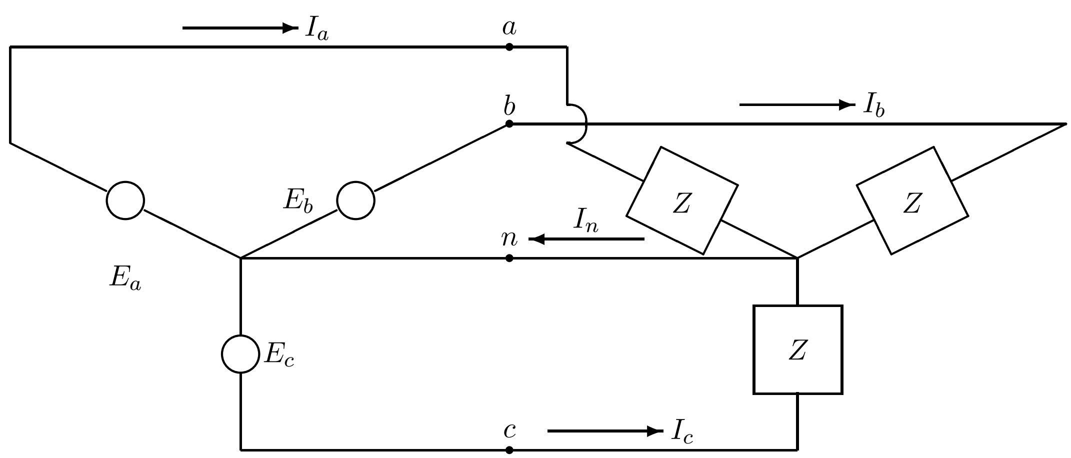

Figure 8: Balanced three-phase wye-connected source and load.

$$I_a = \frac{E_a}{Z} = \frac{|E_a|}{|Z|}\underline{/-\theta} = |I_a|\underline{/-\theta} \qquad \text{A} \tag{23}$$

The other two currents are given by

$$\begin{aligned} I_b &= |I_a|\underline{/-\theta - 120^o} \qquad \text{A} \\ I_c &= |I_a|\underline{/-\theta - 240^o} \qquad \text{A} \end{aligned} \tag{24}$$

The sum of the three currents is the current I_n flowing in the neutral connection, which can easily be shown to be zero in the balanced case.

$$I_n = I_a + I_b + I_c = 0 \ \text{A} \tag{25}$$

The total power supplied to the load is three times the power supplied to each phase.

$$\begin{aligned} |S_{\text{tot}}| &= 3|E_a||I_a| \qquad \text{VA} \\ P_{\text{tot}} &= 3|E_a||I_a|\cos\theta \qquad \text{W} \\ Q_{\text{tot}} &= 3|E_a||I_a|\sin\theta \qquad \text{var} \end{aligned} \tag{26}$$

The total power can also be expressed in terms of the line-to-line voltage E_{ab}.

$$\begin{aligned} |S_{\text{tot}}| &= \sqrt{3}|E_{ab}||I_a| \qquad \text{VA} \\ P_{\text{tot}} &= \sqrt{3}|E_{ab}||I_a|\cos\theta \qquad \text{W} \\ Q_{\text{tot}} &= \sqrt{3}|E_{ab}||I_a|\sin\theta \qquad \text{var} \end{aligned} \tag{27}$$

We shall illustrate the use of these equations in the discussion on synchronous generators in the next section.

3 THE SYNCHRONOUS GENERATOR

Almost all electrical power is generated by three-phase ac generators which are synchronized with the utility grid. Engine driven single-phase generators are used sometimes, primarily for emergency purposes in sizes up to about 50 kW. Single-phase generators would be used for wind turbines only when power requirements are small (less than perhaps 20 kW) and when utility service is only single-phase. A three-phase machine would normally be used whenever the wind turbine is adjacent to a three-phase transmission or distribution line. Three-phase machines tend to be smaller, less expensive, and more efficient than single-phase machines of the same power rating, which explains their use whenever possible.

It is beyond the scope of this text to present a complete treatment of three-phase synchronous generators. This is done by many texts on electrical machines. A brief overview is necessary, however, before some of the important features of ac generators connected to wind turbines can be properly discussed.

A construction diagram of a three-phase ac generator is shown in Fig. 9. There is a rotor which is supplied a direct current I_f through slip rings. The current I_f produces a flux Φ. This flux couples into three identical coils, marked aa', bb', and cc', spaced 120^o apart, and produces three voltage waveforms of the same magnitude but 120 electrical degrees apart.

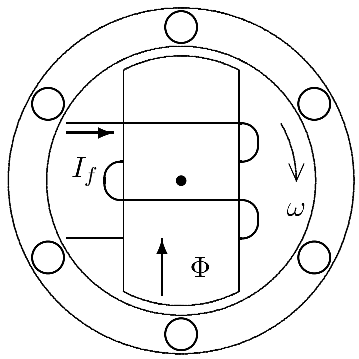

Figure 9: Three-phase generator

The equivalent circuit for one phase of this ac generator is shown in Fig. 10. It is shown in electrical machinery texts that the magnitude of the generated rms *electromotive force* (emf) E is given by

$$|E| = k_1 \omega \Phi \tag{28}$$

where $\omega = 2\pi f$ is the electrical radian frequency, Φ is the flux per pole, and k_1 is a constant which includes the number of poles and the number of turns in each winding. The reactance X_s is the *synchronous reactance* of the generator in ohms/phase. The generator reactance changes from steady-state to transient operation, and X_s is the steady-state value. The resistance R_s represents the resistance of the conductors in the generator windings. It is normally much smaller than X_s, so is normally neglected except in efficiency calculations. The synchronous impedance of the winding is given the symbol $Z_s = R_s + jX_s$.

The voltage E is the open circuit voltage and is sometimes called the voltage behind synchronous reactance. It is the same as the voltage E_a of Fig. 8.

The three coils of the generator can be connected together in either wye or delta, although the wye connection shown in Fig. 8 is much more common. When connected in wye, E is the line to neutral voltage and one has to multiply it by $\sqrt{3}$ to get the magnitude of the line-to-line voltage.

The frequency f of the generated emf is given by

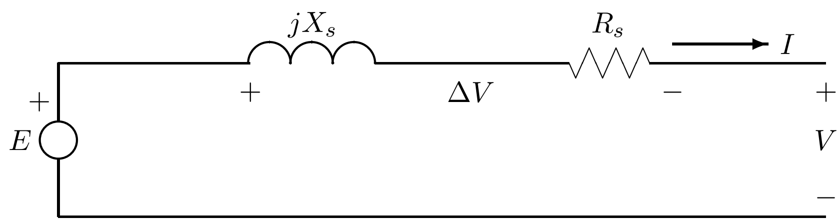

Figure 10: Equivalent circuit for one phase of a synchronous three-phase generator.

$$f = \frac{p}{2}\frac{n}{60} \qquad \text{Hz} \tag{29}$$

where p is the number of poles and n is the rotational speed in r/min. The speed required to produce 60 Hz is 3600 r/min for a two pole machine, 1800 r/min for a four pole machine, 1200 r/min for a six pole machine, and so on. It is possible to build generators with large numbers of poles where slow speed operation is desired. A hydroelectric plant might use a 72 pole generator, for example, which would rotate at 100 r/min to produce 60 Hz power. A slow speed generator could be connected directly to a wind turbine, eliminating the need for an intermediate gearbox. The propellers of the larger wind turbines turn at 40 r/min or less, so a rather large number of poles would be required in the generator for a gearbox to be completely eliminated. Both cost and size of the generator increase with the number of poles, so the system cost with a very low speed generator and no gearbox may be greater than the cost for a higher speed generator and a gearbox.

When the generator is connected to a utility grid, both the grid or terminal voltage V and the frequency f are fixed. The machine emf E may differ from V in both magnitude and phase, so there exists a difference voltage

$$\Delta V = E - V \qquad \text{V/phase} \tag{30}$$

This difference voltage will yield a line current I (defined positive away from the machine) of value

$$I = \frac{\Delta V}{Z_s} \qquad \text{A} \tag{31}$$

The relationship among E, V, and I is shown in the phasor diagram of Fig. 11. E is proportional to the rotor flux Φ which in turn is proportional to the field current flowing in the rotor. When the field current is relatively small, E will be less than V. This is called the *underexcitation* case. The case where E is greater than V is called *overexcitation.* E will lead V by an angle δ while I will lag or lead V by an angle θ.

The conventions for the angles θ and δ are

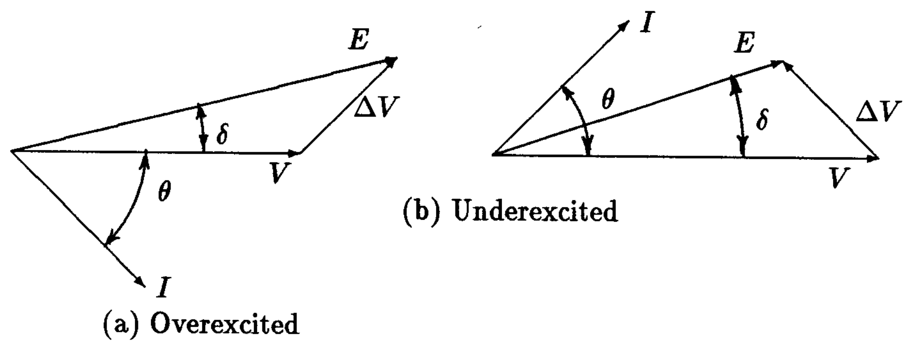

Figure 11: Phasor diagram of one phase of a synchronous three-phase generator: (a) overexcited; (b) underexcited.

$$\begin{aligned} \theta &= \angle V - \angle I \\ \delta &= \angle E - \angle V \end{aligned} \qquad (32)$$

Phasors in the first quadrant have positive angles while phasors in the fourth quadrant have negative angles. Therefore, both θ and δ are positive in the overexcited case, while δ is positive and θ is negative in the underexcited case.

Expressions for the real and reactive powers supplied by each phase were given in Eqs. 14 and 15 in terms of the terminal voltage V and the angle θ. We can apply some trigonometric identities to the phasor diagrams of Fig. 11 and arrive at alternative expressions for P and Q in terms of E, V, and the angle δ.

$$\begin{aligned} P &= \frac{|E||V|}{X_s}\sin\delta \qquad \text{W/phase} \\ Q &= \frac{|E||V|\cos\delta - |V|^2}{X_s} \qquad \text{var/phase} \end{aligned} \qquad (33)$$

A plot of P versus δ is shown in Fig. 12. This illustrates two important points about the use of an ac generator. One is that as the input mechanical power increases, the output electrical power will increase, reaching a maximum at $\delta = 90^o$. This maximum electrical power, occurring at $\sin\delta = 1$, is called the *pullout* power. If the input mechanical power is increased still more, the output power will begin to decrease, causing a rapid increase in δ and a loss of synchronism. If a turbine is operating near rated power, and a sharp gust of wind causes the input power to exceed the pullout power from the generator, the rotor will accelerate above rated speed. Large generator currents will flow and the generator will have to be switched off the power line. Then the rotor will have to be slowed down and the generator resynchronized with the grid. Rapid pitch control of the rotor can prevent this, but the control system will have to be well designed.

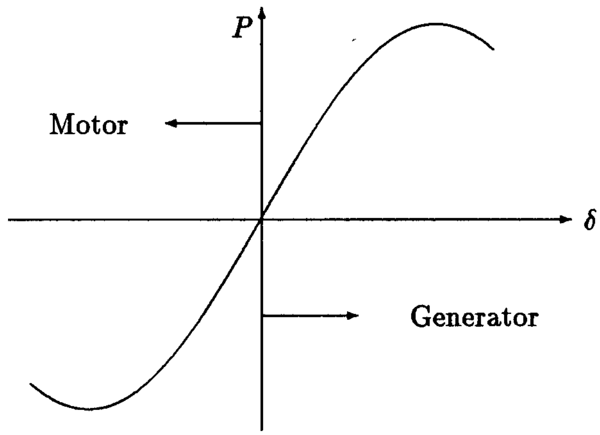

Figure 12: Power flow from an ac generator as a function of power angle.

The other feature illustrated by this power plot is that the power becomes negative for negative δ. This means the generator is now acting as a motor. Power is being taken from the electric utility to operate a giant fan and speed up the air passing through the turbine. This is not the purpose of the system, so when the wind speed drops below some critical value, the generator must be disconnected from the utility line to prevent motoring.

Before working an example, we need to discuss generator rating. Generators are often rated in terms of apparent power rather than real power. The reason for this is the fact that generator losses and the need for generator cooling are not directly proportional to the real power. The generator will have hysteresis and eddy current losses which are determined by the voltage, and ohmic losses which are determined by the current. The generator can be operated at rated voltage and rated current, and therefore with rated losses, even when the real power is zero because $\theta = 90$ degrees. A generator may be operated at power factors between 1.0 and 0.7 or even lower depending on the requirements of the grid, so the product of rated voltage and rated current (the rated apparent power) is a better measure of generator capability than real power. The same argument is true for transformers, which always have their ratings specified in kVA or MVA rather than kW or MW.

A generator may also have a real power rating which is determined by the allowable torque in the generator shaft. A rating of 2500 kVA and 2000 kW, or 2500 kVA at 0.8 power factor, would imply that the machine is designed for continuous operation at 2500 kVA output, with 2000 kW plus losses being delivered to the generator through its shaft. There are always safety factors built into the design for short term overloads, but one should not plan to operate a generator above its rated apparent power or above its rated real power for long periods of time.

We should also note that generators are rarely operated at exactly rated values. A generator rated at 220 V and 30 A may be operated at 240 V and 20 A, for example. The power in the wind is continuously varying, so a generator rated at 2500 kVA and 2000 kW may be delivering 300 kW to the grid one minute and 600 kW the next minute. Even when the source is controllable, as in a coal-fired generating plant, a 700-MW generator may be operated at 400 MW because of low demand. It is therefore important to distinguish between *rated* conditions and *operating* conditions in any calculations.

Rated conditions may not be completely specified on the equipment nameplate, in which case some computation is required. If a generator has a per phase rated apparent power S_R and a rated line to neutral voltage V_R, the rated current is

$$I_R = \frac{S_R}{V_R} \tag{34}$$

Example

The MOD-0 wind turbine has an 1800 r/min synchronous generator rated at 125 kVA at 0.8 pf and 480 volts line to line[8]. The generator parameters are $R_s = 0.033\ \Omega$/phase and $X_s = 4.073\ \Omega$/phase. The generator is delivering 75 kW to the grid at rated voltage and 0.85 power factor lagging. Find the rated current, the phasor operating current, the total reactive power, the line to neutral phasor generated voltage E, the power angle *delta*, the three-phase ohmic losses in the stator, and the pullout power.

The first step in the solution is to determine the per phase value of terminal voltage, which is

$$|V| = \frac{480}{\sqrt{3}} = 277 \ \text{ V/phase}$$

The rated apparent power per phase is

$$S_R = \frac{125}{3} = 41.67 \ \text{ kVA/phase} = 41,670 \ \text{ VA/phase}$$

The rated current is then

$$I_R = \frac{S_R}{V_R} = \frac{41,670}{277} = 150.4 \ \text{ A}$$

The real power being supplied to the grid per phase is

$$P = \frac{75}{3} = 25 \ \text{ kW/phase} = 25 \times 10^3 \ \text{ W/phase}$$

From Eq. 14 we can find the magnitude of the phasor operating current to be

$$|I| = \frac{P}{|V|\cos\theta} = \frac{25 \times 10^3}{277(0.85)} = 106.2 \text{ A}$$

The angle θ is

$$\theta = \cos^{-1}(0.85) = +31.79^o$$

The phasor operating current is then

$$I = |I|\underline{/-\theta} = 106.2\underline{/-31.79^o} = 90.3 - j55.9 \text{ A}$$

The reactive power supplied per phase is

$$Q = (277)(106.2)\sin 31.79^o = 15,500 \text{ var/phase}$$

The generator is then supplying a total reactive power of 46.5 kvar to the grid in addition to the total real power of 75 kW.

The voltage E is given by Kirchhoff's voltage law.

$$\begin{aligned} E = V + IZ_s &= 277\underline{/0^o} + 106.2\underline{/-31.79^o}(0.033 + j4.073) \\ &= 508 + j366 = 626\underline{/35.77^o} \text{ V/phase} \end{aligned}$$

Since the terminal voltage V has been taken as the reference ($V = |V|\underline{/0^o}$), the power angle is just the angle of E, or 35.77^o. The total stator ohmic loss is

$$P_{\text{loss}} = 3I^2R_s = 3(106.2)^2(0.033) = 1.117 \text{ kW}$$

This is a small fraction of the total power being delivered to the utility, but still represents a significant amount of heat which must be transferred to the atmosphere by the generator cooling system.

The pullout power, given by Eq. 33 with $\sin\delta = 1$ is

$$P = \frac{|E||V|}{X_s} = \frac{626(277)}{4.073} = 42.6 \text{ kW/phase}$$

or a total of 128 kW for the total machine. As mentioned earlier, if the input shaft power would rise above the pullout power from a wind gust, the generator would lose synchronism with the power grid. In most systems, the pullout power will be at least twice the rated power of the generator to prevent this possibility. This larger pullout power represents a somewhat better safety margin than is available in the MOD-0 system.

One advantage of the synchronous generator is its ability to supply either inductive or capacitive reactive power to a load. The generated voltage $|E|$ is produced by a current flowing in the field winding, which is controlled by a control system. If the field current is increased, then $|E|$ must increase. If the real power is fixed by the prime mover, then from Eq. 33 we see that $\sin\delta$ must decrease by a proportional amount as $|E|$ increases. This causes the reactive power flow to increase. A decrease in $|E|$ will cause Q to decrease, eventually becoming negative. A synchronous generator rated at 125 kVA and 0.8 power factor can supply its rated real power of 100 kW and at the same time can supply any value of reactive power between +75 kvar and −75 kvar to the grid. Most loads require some reactive power for operation, so the synchronous generator can meet all the requirements of a load while requiring nothing from the load. It can operate in an independent mode as well as intertied with a utility grid.

The major disadvantage of a synchronous generator is its complexity and cost, as well as the cost of the required control systems. Some of the complexity is shown by the synchronization process, as illustrated in Fig. 13. From a complete stop, the first step is to start the rotor. The sensors will measure wind direction and actuate the direction controls so the turbine is properly directed into the wind. If the wind speed is above the cut-in value, the pitch controls will change the propeller pitch so rotation can occur. The generator field control is activated so a predetermined current is sent through the field of the generator. A fixed field current fixes the flux Φ, so that E is proportional to the rotational speed n. The turbine accelerates until it almost reaches rated angular velocity. At this point the frequency of E will be about the same as that of the power grid. The amplitude of E will be about the same as V if the generator field current is correct. Slightly different frequencies will cause the phase difference between E and V to change slowly over the range of 0 to 360^o. The voltage difference V_d is sensed so the relay can be closed when V_d is a minimum. This limits the transient current through the relay contacts, thus prolonging their lives, and also minimizes the shock to both the generator and the power grid. If the relay is closed when V_d is not close to its minimum, very high currents will flow until the generator is accelerated or decelerated to the rotational position where E and V are in phase.

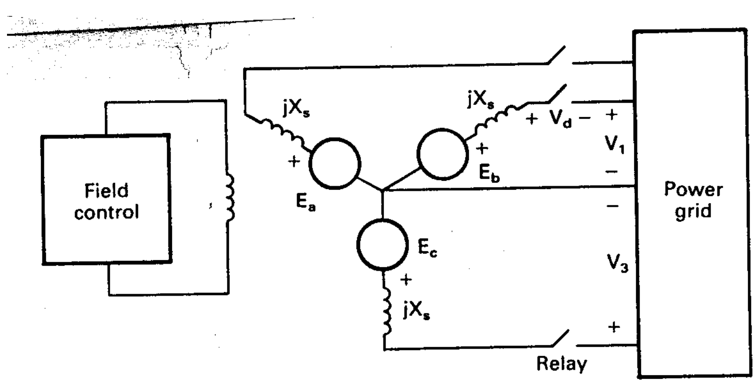

Figure 13: AC generator being synchronized with the power grid.

Once the relay is closed, there will still be no power flow as long as E and V have the same magnitude and phase. Generator action is obtained by increasing the magnitude of E with the field control. The pitch controller sets the blade pitch at the optimum point if the blades are not already at this point. The blade torque will attempt to accelerate the generator, but this is impossible because the generator and the power grid are in synchronism. The torque will advance the relative position of the generator rotor with respect to the power grid voltage, however, so E will lead V by the power angle δ. The input mechanical power to the generator is fixed for a given wind speed and blade pitch, which also fixes the output power. If $|E|$ is changed by the generator field control, then the power angle will change automatically to maintain this fixed output power.

This synchronization process may sound very difficult, but is accomplished routinely by automatic equipment. If the wind speed and blade pitch are such that the turbine and generator are slowly accelerating through synchronous speed, the relay can usually be closed just as synchronous speed is reached. The microprocessor control would then adjust the field current and the blade pitch for proper operating conditions. An observer would see a smooth operation lasting only a minute or so.

The control systems necessary for synchronization and the generator field supply are not cheap. On the other hand, their costs are not strongly dependent on system size over the normal range of wind turbine sizes. This means that the control systems would form a small fraction of the total turbine cost for a 1000-kW turbine, but a substantial fraction for a 5-kW turbine. For this reason, the synchronous generator will be more common in sizes of 100 kW and up, and not so common in the smaller sizes.

4 PER UNIT CALCULATIONS

Problems such as those in the previous section can always be worked using the actual circuit values. There is an alternative, however, to the use of actual circuit values which has several advantages and which is widely used in the electric power industry. This is the *per unit* system, in which voltages, currents, powers, and impedances are all expressed as a percent or per unit of a base or reference value. For example, if a base voltage of 120 V is chosen, voltages of 108, 120, and 126 V become 0.90, 1.00, and 1.05 per unit, or 90, 100, and 105 percent, respectively. The per unit value of any quantity is defined as the ratio of the quantity to its base value, expressed as a decimal.

One advantage of the per unit system is that the product of two quantities expressed in per unit is also in per unit. Another advantage is that the per unit impedance of an ac generator is essentially a constant for a wide range of actual sizes. This means that a problem like the preceding example needs to be worked only once in per unit, with the results converted to actual values for each particular size of machine for which results are needed.

We shall choose the base or reference as the per phase quantities of a three-phase system.

The base radian frequency $\omega_{\text{base}} = \omega_o$ is the rated radian frequency of the system, normally

$2\pi(60) = 377$ rad/s.

Given the base apparent power per phase S_{base} and base line to neutral voltage V_{base}, the following relationships are valid:

$$I_{\text{base}} = \frac{S_{\text{base}}}{V\text{base}} \qquad \text{A} \tag{35}$$

$$Z_{\text{base}} = R_{\text{base}} = X_{\text{base}} = \frac{V_{\text{base}}}{I_{\text{base}}} \qquad \Omega \tag{36}$$

$$P_{\text{base}} = Q_{\text{base}} = S_{\text{base}} \qquad \text{VA} \tag{37}$$

We may even define a base inductance and a base capacitance.

$$L_{\text{base}} = \frac{X_{\text{base}}}{\omega_o} \tag{38}$$

$$C_{\text{base}} = \frac{1}{X_{\text{base}}\omega_o} \tag{39}$$

The per unit values are then the actual values divided by the base values.

$$V_{\text{pu}} = \frac{V}{V_{\text{base}}} \tag{40}$$

$$I_{\text{pu}} = \frac{I}{I\text{base}} \tag{41}$$

$$Z_{\text{pu}} = \frac{Z}{Z\text{base}} \tag{42}$$

$$\omega_{\text{pu}} = \frac{\omega}{\omega_{\text{base}}} = \frac{\omega}{\omega_o} \tag{43}$$

$$L_{\text{pu}} = \frac{L}{L_{\text{base}}} \tag{44}$$

$$C_{\text{pu}} = \frac{C}{C_{\text{base}}} \tag{45}$$

Example

The MOD-2 generator is rated at 3125 kVA, 0.8 pf, and 4160 V line to line. The typical per phase synchronous reactance for the four-pole, conventionally cooled generator is 1.38 pu. The generator is supplying power at rated voltage and frequency to an isolated load with a per phase impedance of 1.2 - j0.8 pu as shown in Fig. 14. Find the base, actual, and per unit values of terminal voltage V, generated voltage E, apparent power, real power, reactive power, current, generator inductance, and load capacitance.

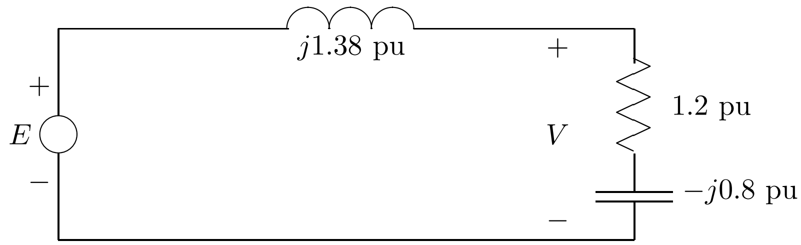

Figure 14: Per phase diagram for example problem.

First we determine the base values, which do not depend on actual operating conditions but on nameplate ratings.

$$V_{\rm base} = \frac{4160}{\sqrt{3}} = 2400 \ \ {\rm V}$$

$$E_{\rm base} = V_{\rm base} = 2400 \ \ {\rm V}$$

$$S_{\rm base} = \frac{3125}{3} = 1042 \ \ {\rm kVA}$$

$$P_{\rm base} = Q_{\rm base} = S_{\rm base} = 1042 \ \ {\rm kVA}$$

$$I_{\rm base} = \frac{S_{\rm base}}{V_{\rm base}} = \frac{1,042,000 \ \ {\rm VA}}{2400 \ \ {\rm V}} = 434 \ \ {\rm A}$$

$$Z_{\rm base} = \frac{V_{\rm base}}{I_{\rm base}} = \frac{2400}{434} = 5.53 \ \ \Omega$$

$$L_{\rm base} = \frac{X_{\rm base}}{\omega_o} = \frac{Z_{\rm base}}{\omega_o} = \frac{5.53}{377} = 14.7 \ \ {\rm mH}$$

$$C_{\rm base} = \frac{1}{X_{\rm base}\omega_o} = \frac{1}{5.53(377)} = 480 \ \ \mu{\rm F}$$

The actual voltage is given in the problem as the rated or base voltage, so

$$V = 2400 \text{ V}$$

The per unit terminal voltage is then

$$V_{\rm pu} = \frac{V}{V_{\rm base}} = \frac{2400}{2400} = 1$$

We now have to solve for the per unit current.

$$\begin{aligned} I_{\rm pu} &= \frac{V_{\rm pu}}{Z_{\rm pu}} = \frac{1\underline{/0^o}}{1.2 - j0.8} = \frac{1\underline{/0^o}}{1.44\underline{/-33.69^o}} = 0.693\underline{/33.69^o} \\ &= 0.577 + j0.384 \end{aligned}$$

The actual current is

$$I = I_{\rm pu} I_{\rm base} = (0.693\underline{/33.69^o})(434) = 300\underline{/33.69^o} \text{ A}$$

The per unit apparent power is

$$S_{\rm pu} = |V_{\rm pu}||I_{\rm pu}| = (1)(0.693) = 0.693$$

The per unit real power is

$$P_{\rm pu} = |V_{\rm pu}||I_{\rm pu}|\cos\theta = (1)(0.693)\cos(-33.69^o) = 0.577$$

The per unit reactive power is

$$Q_{\rm pu} = |V_{\rm pu}||I_{\rm pu}|\sin\theta = (1)(0.693)\sin(-33.69^o) = -0.384$$

The actual powers per phase are

$$\begin{aligned} S &= (0.693)(1042) = 722 \text{ kVA/phase} \\ P &= (0.577)(1042) = 600 \text{ kW/phase} \\ Q &= (-0.384)(1042) = -400 \text{ kvar/phase} \end{aligned}$$

The total power delivered to the three-phase load would then be 2166 kVA, 1800 kW, and -1200 kvar.

The generated voltage E in per unit is

$$\begin{aligned} E_{\rm pu} &= V_{\rm pu} + I_{\rm pu}(jX_{s,\rm pu}) = 1 + 0.693\underline{/33.69^o}(1.38)\underline{/90^o} \\ &= 1 + 0.956\underline{/123.69^o} = 1 - 0.530 + j0.796 \\ &= 0.470 + j0.796 = 0.924\underline{/59.46^o} \end{aligned}$$

The per unit generator inductance per phase is

$$L_{\rm pu} = \frac{X_{s,\rm pu}}{\omega_{\rm pu}} = \frac{1.38}{1} = 1.38$$

The actual generator inductance per phase is

$$L = L_{\rm pu} L_{\rm base} = 1.38(14.7) = 20.3 \ \ \text{mH}$$

The per unit load capacitance per phase is

$$C_{\rm pu} = \frac{1}{X_{C,\rm pu}\omega_{\rm pu}} = \frac{1}{0.8(1)} = 1.25$$

The actual load capacitance per phase is

$$C = C_{\rm pu} C_{\rm base} = 1.25(480) = 600 \ \ \mu\text{F}$$

The base of any device such as an electrical generator, motor, or transformer is always understood to be the nameplate rating of the device. The per unit impedance is usually available from the manufacturer.

Sometimes the base values need to be changed to a common base when several devices are connected together. Solving an electrical circuit requires either the actual impedances or the per unit impedances referred to a common base. The per unit impedance on the old base can be converted to the per unit impedance for the new base by

$$Z_{\rm pu,new} = Z_{\rm pu,old}\left(\frac{V_{\rm base,old}}{V_{\rm base,new}}\right)^2 \frac{S_{\rm base,new}}{S_{\rm base,old}} \tag{46}$$

Example

A single-phase distribution transformer secondary is rated at 60 Hz, 10 kVA, and 240 V. The open circuit voltage V_{oc} is 240 V. The per unit series impedance of the transformer is $Z = 0.005 + \text{j}0.03$. Two electric heaters, one rated 1500 W and 230 V, and the other rated at 1000 W and 220 V, are connected to the transformer. Find the per unit transformer current $I_{\rm pu}$ and the magnitude of the actual load voltage V_1, as shown in Fig. 15.

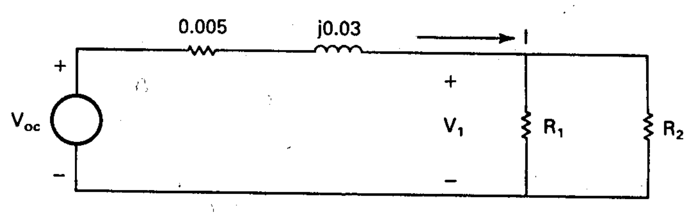

Figure 15: Single-phase transformer connected to two resistive loads.

The first step is to get all impedance values computed on the same base. Any choice of base will work, but minimum effort will be exerted if we choose the transformer base as the reference base. This yields $V_{\rm base} = 240$ V and $S_{\rm base} = 10$ kVA. The per unit values of the electric heater resistances would be unity on their nameplate ratings. The per unit values referred to the transformer rating would be

$$R_{1,\rm pu} = (1)\left(\frac{230}{240}\right)^2 \frac{10}{1.5} = 6.12$$

$$R_{2,\rm pu} = (1)\left(\frac{220}{240}\right)^2 \frac{10}{1} = 8.40$$

The equivalent impedance of these heaters in parallel would be

$$R_{\rm pu} = \frac{6.12(8.40)}{6.12 + 8.40} = 3.54$$

The per unit current is then

$$I_{\rm pu} = \frac{V_{\rm oc,pu}}{Z_{\rm pu} + R_{\rm pu}} = \frac{1}{0.005 + j0.03 + 3.54} = 0.282\underline{/-0.48^o}$$

The load voltage magnitude is

$$|V_1| = I_{\rm pu} R_{\rm pu} V_{\rm base} = 0.282(3.54)(240) = 239.6 \ \ \text{V}$$

The voltage V_1 has decreased only 0.4 V from the open circuit value for a current of 28.2 percent of rated. This indicates the voltage varies very little with load changes, which is quite desirable for transformer outputs.

5 THE INDUCTION MACHINE

A large fraction of all electrical power is consumed by induction motors. For power inputs of less than 5 kW, these may be either single-phase or three-phase, while the larger machines are almost invariably designed for three-phase operation. Three- phase machines produce a constant torque, as opposed to the pulsating torque of a single-phase machine. They also produce more power per unit mass of materials than the single-phase machine. The three-phase motor is a very rugged piece of equipment, often lasting for 50 years with only an occasional change of bearings. It is simple to construct, and with mass production is relatively inexpensive. The same machine will operate as either a motor or a generator with no modifications, which allows us to have a rugged, inexpensive generator on a wind turbine with rather simple control systems.

The basic wiring diagram for a three-phase induction motor is shown in Fig. 16. The motor consists of two main parts, the *stator* or stationary part and the *rotor*. The most common type of rotor is the *squirrel cage*, where aluminum or copper bars are formed in longitudinal slots in the iron rotor and are short circuited by a conducting ring at each end of the rotor. The construction is very similar to a three-phase transformer with the secondary shorted, and the same circuit models apply. In operation, the currents flowing in the three stator windings produce a rotating flux. This flux induces voltages and currents in the rotor windings. The flux then interacts with the rotor currents to produce a torque in the direction of flux rotation.

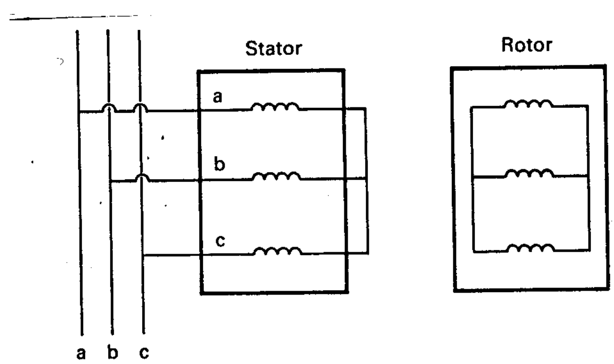

Figure 16: Wiring diagram for a three-phase induction motor.

The equivalent circuit of one phase of an induction motor is given in Fig. 17. In this circuit, R_m is an equivalent resistance which represents the losses due to eddy currents, hysteresis, windage, and friction, X_m is the magnetizing reactance, R_1 is the stator resistance, R_2 is the rotor resistance, X_1 is the leakage reactance of the stator, X_2 is the leakage reactance of the rotor, and s is the slip. All resistance and reactance values are referred to the stator. The reactances X_1 and X_2 are difficult to separate experimentally and are normally assumed equal to each other. The *slip* may be defined as

$$s = \frac{n_s - n}{n_s} \tag{47}$$

where n_s is the synchronous rotational speed and n is the actual rotational speed. If the synchronous frequency is 60 Hz, then from Eq. 29 the synchronous rotational speed will be

$$n_s = \frac{7200}{p} \qquad \text{r/min} \tag{48}$$

where p is the number of poles.

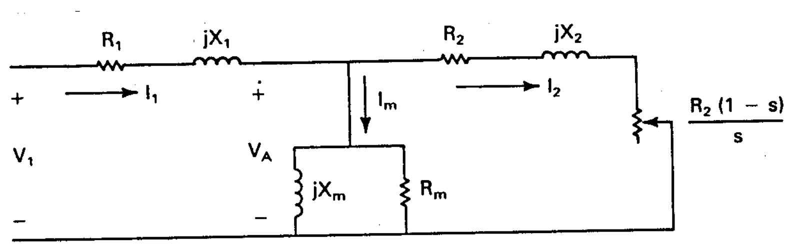

Figure 17: Equivalent circuit for one phase of a three-phase induction motor

The total losses in the motor are given by

$$P_{\text{loss}} = \frac{3|V_A|^2}{R_m} + 3|I_1|^2 R_1 + 3|I_2|^2 R_2 \qquad \text{W} \tag{49}$$

The first term is the loss due to eddy currents, hysteresis, windage, and friction. The second term is the winding loss (copper loss) in the stator conductors and the third term is the winding loss in the rotor. The factor of 3 is necessary because of the three phases.

The power delivered to the resistance at the right end of Fig. 17 is

$$P_{m,1} = \frac{|I_2|^2 R_2 (1-s)}{s} \qquad \text{W/phase} \tag{50}$$

The power $P_{m,1}$ is not actually dissipated as heat inside the motor but is delivered to a load as mechanical power. The total three-phase power delivered to this load is

$$P_m = \frac{3|I_2|^2 R_2 (1-s)}{s} \qquad \text{W} \tag{51}$$

To analyze the circuit in Fig. 17, we first need to find the impedance Z_{in} which is seen by the voltage V_1. We can define the impedance of the right hand branch as

$$Z_2 = R_2 + jX_2 + \frac{R_2(1-s)}{s} = \frac{R_2}{s} + jX_2 \qquad \Omega \tag{52}$$

The impedance of the shunt branch is

$$Z_m = \frac{jX_m R_m}{R_m + jX_m} \qquad \Omega \tag{53}$$

The input impedance is then

$$Z_{\rm in} = R_1 + jX_1 + \frac{Z_m Z_2}{Z_m + Z_2} \qquad \Omega \tag{54}$$

The input current is

$$I_1 = \frac{V_1}{Z_{\rm in}} \qquad \text{A} \tag{55}$$

The voltage across the shunt branch is

$$V_A = V_1 - I_1(R_1 + jX_1) \qquad \text{V} \tag{56}$$

The shunt current I_m is given by

$$I_m = \frac{V_A}{Z_m} \qquad \text{A} \tag{57}$$

The current I_2 is given by

$$I_2 = \frac{V_A}{Z_2} \qquad \text{A} \tag{58}$$

The motor efficiency η_m is defined as the ratio of output power to input power.

$$\eta_m = \frac{P_m}{P_m + P_{\rm loss}} \tag{59}$$

The relationship between motor power P_m and motor torque T_m is

$$P_m = \omega_m T_m \qquad \text{W} \tag{60}$$

where

$$\omega_m = \frac{2\pi n}{60} = \frac{\pi}{30}(1 - s)n_s \qquad \text{rad/s} \tag{61}$$

By combining the last three equations we obtain the total motor torque

$$T_m = \frac{90|I_2|^2 R_2}{\pi n_s s} \qquad \text{N} \cdot \text{m/rad} \tag{62}$$

A typical plot of motor torque versus angular velocity appears in Fig. 18. Also shown is a possible variation of load torque T_{mL}. At start, while $n = 0$, T_m will be greater than T_{mL}, allowing the motor to accelerate. As n increases, T_m increases to a maximum and then declines rather rapidly toward zero at $n = n_s$. Meanwhile the torque required by the load is increasing with speed. The two torques are equal and steady state operation is reached at point a in Fig. 18. Rated torque is usually reached at a speed about 3 percent less than synchronous speed. A four pole induction motor will therefore deliver rated torque at about 1740 r/min, as compared with the synchronous speed of 1800 r/min. The no load speed will be less than synchronous speed by a few revolutions per minute. The reason for this is that at synchronous speed the rotor conductors turn in unison with the stator field, which means there is no time changing magnetic field passing through these conductors to induce a voltage. Without a voltage there will be no rotor current I_2, and there is no torque without a current.

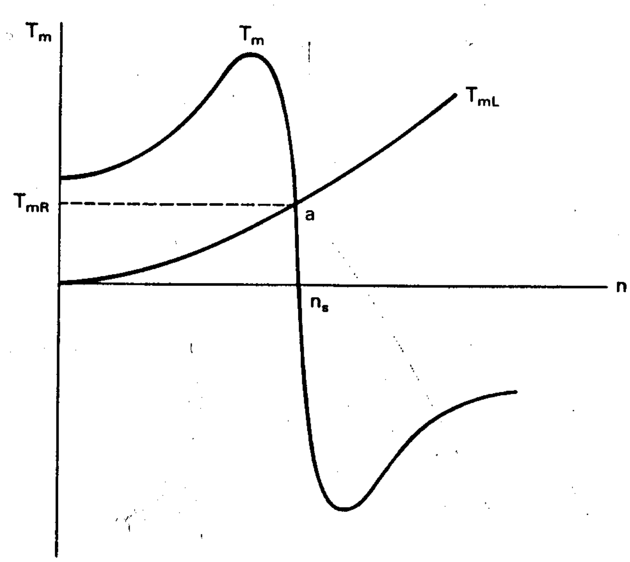

Figure 18: Variation of shaft torque with speed for a three-phase induction machine.

If synchronous speed is exceeded, s, T_m, and P_m all become negative, indicating that the mechanical load has become a prime mover and the motor is now acting as a generator. This means that an induction machine can be connected across a three-phase line, used as a motor to start a wind turbine such as a Darrieus, and become a generator when the wind starts to turn the Darrieus. The Darrieus has no pitch control, the induction machine has no field control, and synchronization is unnecessary, so equipment costs are significantly reduced from those of the system using a synchronous generator.

The circuit of the induction generator is identical to that of the induction motor, except that we sometimes draw it reversed, with reversed conventions for I_1 and I_2 as shown in Fig. 19. The resistance $R_2(1 - s)/s$ is negative for negative slip, and this negative resistance can be thought of as a source of power.

The induction generator requires reactive power for excitation. It cannot operate without this reactive power, so when the connection to the utility is broken in Fig. 19, the induction

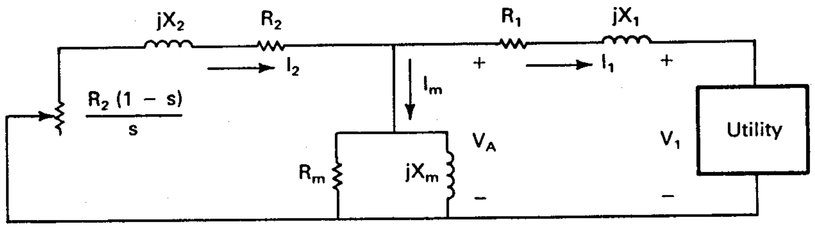

Figure 19: Equivalent circuit of one phase of an induction generator.

generator receives no reactive power and is not able to generate real power. This makes it somewhat less versatile than the synchronous generator which is able to supply both real and reactive power to the grid. The induction generator requirement for reactive power can also be met by capacitors connected across the generator terminals. If the proper values of capacitance are selected, the generator will operate in a self-excited mode and can operate independently of the utility grid. This possibility is examined in Chapter 6.

The rated electrical output power of the induction generator will be very close to the rated electrical input power of the same machine operated as a motor. If we maintain the same rated current I_1 at rated voltage V_1 for both generator and motor operation, the machine will have the same stator copper losses. The rotor current is proportional to I_2 and will be larger for generator operation than for motor operation, as can be seen by comparing Fig. 17 and Fig. 19. This will increase the rotor losses somewhat. The machine is running at 3-5 percent above synchronous speed as a generator, so windage and friction losses are somewhat higher than for motor operation. The saturation of the iron in the machine will be somewhat higher as a generator so hysteresis and eddy current losses will also be somewhat higher. These greater losses are counterbalanced by two effects. One is that the same wind which is driving the turbine is also cooling the generator. A wind turbine application presents a much better cooling environment to an induction machine than most applications, and this needs to be included in the system design. The second effect is that the wind is not constant. Short periods of overload would normally be followed by operation at less than rated power, which would allow the machine to cool. These cooling effects should allow the generator rating to be equal to the motor rating for a given induction machine.

It may well be that generator temperature will be used as a control signal for overload protection rather than generator current or power. The generator is not harmed by delivering twice its rated power for some period of time as long as its rated temperature is not exceeded. Using temperature as a control variable will therefore fully utilize the capability of the machine and allow a somewhat greater energy production than would be possible when using power or current as the control variable.

The analysis of the induction generator proceeds much the same as the analysis of the induction motor. The expressions for impedance in Eqs. 52 –54 keep the same form. The negative slip causes the real parts of Z_2 and Z_{in} to be negative, but this is easily carried along in the computations. The change in assumed direction for I_1 and I_2 forces us to write their equations as

$$I_1 = -\frac{V_1}{Z_{\text{in}}} \tag{63}$$

$$I_2 = -\frac{V_A}{Z_2} \tag{64}$$

The voltage V_A is given by

$$V_A = V_1 + I_1(R_1 + jX_1) \tag{65}$$

The real power P_m supplied by the turbine is the same as Eq. 51. The negative sign resulting from negative slip just means that power is flowing in the opposite direction. P_m is now the input power so the generator efficiency η_g would be given by

$$\eta_g = \frac{|P_m| - P_{\text{loss}}}{|P_m|} \tag{66}$$

The total real power delivered to the utility by the generator is

$$P_e = 3|V_1||I_1|\cos\theta \qquad \text{W} \tag{67}$$

where V_1 is the line to neutral voltage and θ is the angle between voltage and current as defined by Eq. 16.

The total reactive power Q required by the generator is given by

$$Q = 3|I_2|^2 X_2 + \frac{3|V_A|^2}{X_m} + 3|I_1|^2 X_1 \qquad \text{var} \tag{68}$$

It is also given by the expression

$$Q = 3|I_1||V_1|\sin\theta \qquad \text{var} \tag{69}$$

Example

A three-phase, Y-connected, 220-V (line to line), 10-hp, 60-Hz, six-pole induction machine has the following constants in ohms per phase:

$$R_1 = 0.30 \;\; \Omega/\text{phase} \qquad R_2 = 0.14 \;\; \Omega/\text{phase} \qquad R_m = 120 \;\; \Omega/\text{phase}$$

$$X_1 = X_2 = 0.35 \;\; \Omega/\text{phase} \qquad X_m = 13.2 \;\; \Omega/\text{phase}$$

For a slip $s = 0.025$ (operation as a motor), compute I_1, V_A, I_m, I_2, speed in r/min, total output torque and power, power factor, total three-phase losses, and efficiency.

The applied voltage to neutral is

$$V_1 = \frac{220}{\sqrt{3}} = 127\underline{/0^o} \text{ V/phase}$$

$$Z_2 = \frac{R_2}{s} + jX_2 = \frac{0.14}{0.025} + j0.35 = 5.60 + j0.35 = 5.61\underline{/3.58^o} \;\Omega$$

$$Z_m = \frac{jR_mX_m}{R_m + jX_m} = \frac{j(120)(13.2)}{120 + j13.2} = \frac{1584\underline{/90^o}}{120.72\underline{/6.28^o}} = 13.12\underline{/83.72^o} \;\Omega$$

$$Z_{\rm in} = R_1 + jX_1 + \frac{Z_mZ_2}{Z_m + Z_2} = 0.30 + j0.35 + \frac{(13.12\underline{/83.72^o})(5.61\underline{/3.58^o})}{13.12\underline{/83.72^o} + 5.61\underline{/3.58^o}} = 5.29\underline{/27.08^o} \;\Omega$$

$$I_1 = \frac{V_1}{Z_{\rm in}} = \frac{127\underline{/0^o}}{5.29\underline{/27.08^o}} = 24.01\underline{/-27.08^o} \text{ A}$$

$$\begin{aligned} V_A &= V_1 - I_1(R_1 + jX_1) = 127 - 24.01\underline{/-27.08^o}(0.30 + j0.35) \\ &= 116.76 - j4.20 = 116.84\underline{/-2.06^o} \text{ V} \end{aligned}$$

$$I_m = \frac{V_A}{Z_m} = \frac{116.84\underline{/-2.06^o}}{13.12\underline{/83.72^o}} = 8.91\underline{/-85.78^o} \text{ A}$$

$$I_2 = \frac{V_A}{Z_2} = \frac{116.84\underline{/-2.06^o}}{5.61\underline{/3.58^o}} = 20.83\underline{/-5.64^o} \text{ A}$$

From Eq. 48 we have

$$n_s = \frac{7200}{6} = 1200 \text{ r/min}$$

From Eq. 47 the speed is

$$n = (1 - s)n_s = (1 - 0.025)1200 = 1170 \text{ r/min}$$

The total torque is given by Eq. 62.

$$T_m = \frac{90|I_2|^2 R_2}{\pi n_s s} = \frac{90(20.83)^2(0.14)}{\pi(1200)(0.025)} = 58.01 \ \text{N}\cdot\text{m/rad}$$

The total mechanical power is then

$$P_m = \omega_m T_m = \frac{2\pi n T_m}{60} = \frac{2\pi(1170)(58.01)}{60} = 7107 \ \text{W}$$

At 746 W/hp, the motor is delivering 9.53 hp to the load. From Eq. 17, the power factor is the cosine of the angle between the input voltage and current, or in this case,

$$\text{pf} = \cos 27.08^o = 0.890 \ \text{lag}$$

From Eq. 49 the total three-phase losses are

$$P_{\text{loss}} = \frac{3(116.84)^2}{120} + 3(24.01)^2(0.30) + 3(20.83)^2(0.14) = 1042 \ \text{W}$$

The efficiency is given by Eq. 59.

$$\eta_m = \frac{P_m}{P_m + P_{\text{loss}}} = \frac{7107}{7107 + 1042} = 0.872$$

The efficiency is 87.2 percent, a typical value for induction motors of this size.

Example

For the machine of the previous example, compute the input current, total starting torque, and total three-phase losses while the machine is being started (while the slip is still essentially unity). Assume the source is able to maintain rated voltage during the start.

With the slip $s = 1$, the impedance Z_2 becomes

$$Z_2 = \frac{0.14}{1} + j0.35 = 0.377\underline{/68.20^o} \ \Omega$$

The shunt impedance Z_m remains the same as before. The input impedance is then

$$Z_{\text{in}} = 0.30 + j0.35 + \frac{13.12\underline{/83.72^o}(0.377\underline{/68.20^o})}{13.12\underline{/83.72^o} + 0.377\underline{/68.20^o}} = 0.816\underline{/57.92^o} \ \Omega$$

$$I_1 = \frac{127\underline{/0^o}}{0.816\underline{/57.92^o}} = 155.58\underline{/-57.92^o} \ \text{A}$$

$$V_A = 127 - 155.58\underline{/-57.92^o}(0.30 + j0.35) = 57.07\underline{/-10.73^o} \ \text{V}$$

$$I_2 = \frac{57.07\underline{/-10.73^o}}{0.377\underline{/68.2^o}} = 151.38\underline{/-78.93^o} \text{ A}$$

The total torque is

$$T_m = \frac{90|I_2|^2 R_2}{\pi n_s s} = \frac{90(151.38)^2(0.14)}{\pi(1200)(1)} = 76.59 \text{ N}\cdot\text{m/rad}$$

This torque is 1.25 times the rated running torque for this particular machine. A majority of induction motors will have a starting torque which is about double the rated running torque.

The total three-phase losses will be

$$P_{\text{loss}} = \frac{3(57.07)^2}{120} + 3(155.58)^2(0.30) + 3(151.38)^2(0.14) = 31,500 \text{ W}$$

This number is about 30 times the loss term for the machine operating at full load. Also, when the machine is not rotating, it is not able to circulate any air for cooling, which makes the temperature rise even more severe. The stator windings will have the most rapid temperature rise for starting conditions because of higher resistance, lower specific heat capacity, and poorer heat conductivity than the rotor windings. This temperature rise may be on the order of 10^oC/s as long as the rotor is not moving. Obviously, the motor will be damaged if this locked rotor situation continues more than a few seconds.

An unloaded motor will typically start in 0.05 s and one with a typical load will usually start in less than 1 s, so this heating is not normally a problem. If a very high inertia load is to be started, such as a large Darrieus, a clutch may be necessary between the motor and the turbine. Very large motors may need special starting techniques even with a clutch. These will be discussed in the next section.

Example

The induction machine of the previous example is operated as a generator at a slip of -0.025. Terminal voltage is 220 V line to line. Find I_1, I_2, input power P_m, output power P_e, reactive power Q, and efficiency η_g. If the rated I_1 is 25 A when operated as a motor, comment on the amount of overload, if any.

From the previous example we have $V_1 = 127\underline{/0^o}$. The impedance Z_2 is given by

$$Z_2 = \frac{0.14}{-0.025} + j0.35 = 5.61\underline{/176.42^o} \ \Omega$$

$$Z_{\text{in}} = 0.30 + j0.35 + \frac{13.12\underline{/83.72^o}(5.61\underline{/176.42^o})}{13.12\underline{/83.72^o} + 5.61\underline{/176.42^o}} = 5.16\underline{/147.90^o} \ \Omega$$

$$I_1 = -\frac{127\underline{/0^o}}{5.16\underline{/147.90^o}} = -24.60\underline{/-147.90^o} = 24.60\underline{/32.10^o} \text{ A}$$

$$V_A = 127 + 24.60\underline{/32.10^o}(0.30 + j0.35) = 129.16\underline{/4.98^o} \text{ V}$$

$$I_2 = \frac{-129.16\underline{/4.98^o}}{5.61\underline{/176.42^o}} = \frac{129.16\underline{/184.98^o}}{5.61\underline{/176.42^o}} = 23.02\underline{/8.56^o} \text{ A}$$

The total input mechanical power P_m is

$$P_m = \frac{3|I_2|^2 R_2(1-s)}{s} = \frac{3(23.02)^2(0.14)(1+0.025)}{-0.025} = -9125 \text{ W}$$

The machine was delivering 9.53 hp to the mechanical load as a motor, but is now requiring 12.23 hp as mechanical shaft power input as a generator. The total output power is

$$P_e = 3|V_1||I_1|\cos\theta = 3(127)(24.60)\cos(-32.10^o) = 7940 \text{ W}$$

The total reactive power Q is

$$Q = 3|V_1||I_1|\sin\theta = 3(127)(24.60)\sin(-32.10^o) = -4980 \text{ var}$$

The negative sign means that the induction generator is supplying negative reactive power to the utility, which is the same as saying it is receiving positive reactive power from the utility.

We can compute the efficiency by computing the losses from Eq. 49 and using Eq. 61, or we can merely take the ratio of output to input power.

$$\eta_g = \frac{|P_e|}{|P_m|} = \frac{7940}{9125} = 0.870$$

The output current of 24.60 A is slightly under the rated current of 25 A. If the machine is well ventilated, it should operate at this current level for an indefinite period of time.

6 MOTOR STARTING

Small induction motors with low to medium inertia loads are normally started by direct connection to a source of rated voltage. Above a rated power of a few kW, the high starting currents usually cause a reduction in line voltage. This reduction may prevent the motor from developing adequate torque to start its load. Electronic equipment and lighting circuits connected to the same source may also be affected by these voltage fluctuations. It is customary, therefore, to start the large induction motors on lowered voltages to limit the starting currents and line voltage fluctuations.

This practice is not essential if the supply has sufficient capacity to supply the starting current without objectionable voltage reduction. Motors with ratings up to several thousand kW are routinely started across line voltage in generating stations, where a starting current of 5 to 10 times the rated current can easily be supplied. The motor itself will not be damaged by these high currents unless they are sustained long enough to overheat the motor.

There are three basic ways to accomplish reduced-voltage starting. These are illustrated in Fig. 20.

1. Line resistance or reactance starting uses series resistances or reactances in each line to provide a voltage drop and reduce the voltage at the motor terminals. After a suitable time delay these components are removed in one or more steps. The notation L_1, L_2, and L_3 refers to the three phases of the incoming power line.
2. Autotransformer starting uses tapped autotransformers to reduce the motor voltage. These taps normally provide between 50 and 80 percent of rated voltage.
3. Wye-delta starting is used when the motor is designed for delta operation but has both ends of each phase winding available external to the motor. The phase windings are reconnected by contactors into a wye circuit for starting. Once the motor is running, it is changed back to its normal delta configuration. This technique reduces the voltage seen by each phase by the factor $\sqrt{3}$.

Complete circuits would include push button start and stop, fuses, and undervoltage protection as well as other features to meet electrical codes. In each case a triple-pole switch is moved to the start position until the motor has accelerated the load to almost full speed, and then rapidly thrown to the run position, so that the motor is connected directly across the line.

The autotransformer has the same characteristic as a two winding transformer in that the input and output apparent power in kVA have to be the same, except for any transformer losses. Fig. 21 shows an autotransformer supplying power to an induction motor. V_L and I_L are the voltage and current supplied by the line and V_1 and I_1 are the voltage and current delivered to the motor. For an ideal transformer

$$V_L I_L = V_1 I_1 \tag{70}$$

Transformer operation requires that V_1 be less than V_L, which means I_L will be less than I_1. Because of the nature of the load, when V_1 is reduced below its rated value, I_1 will also be reduced. The starting current supplied by the line is therefore reduced by both the autotransformer action and by the reduced motor voltage, which makes autotransformer starting rather popular on limited capacity lines.

Example

An autotransformer starting system is used to reduce the voltage to the motor of the examples in the previous section to 0.6 of its rated value. Find the motor starting current I_1, the line current input I_L to the autotransformer, the total motor losses at start, and the total starting torque.

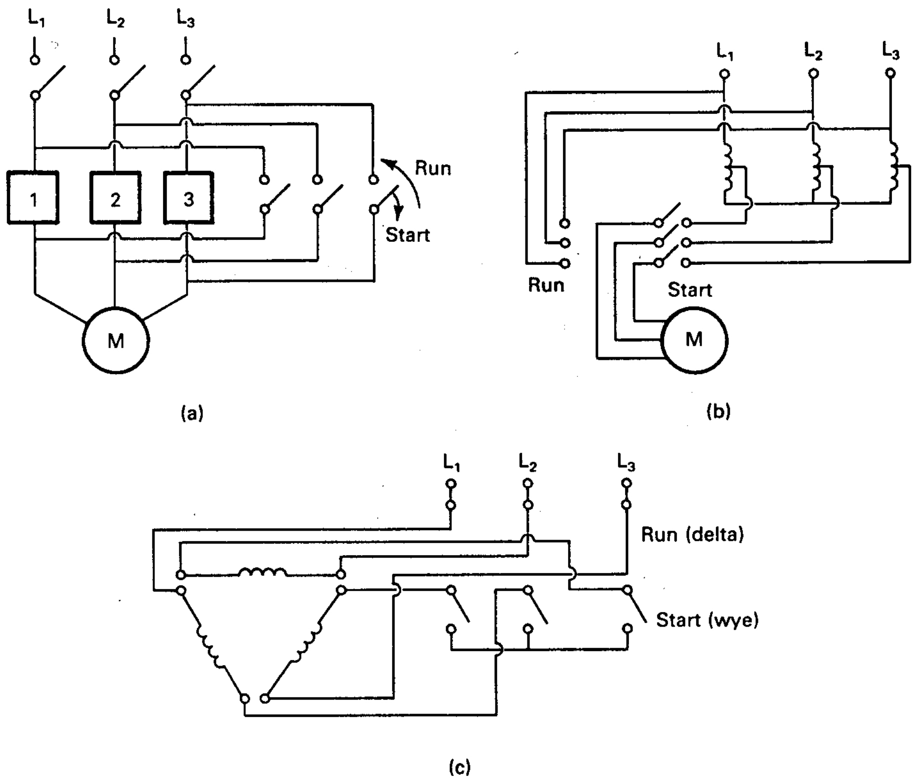

Figure 20: Starting methods for induction motors: (a) line resistance or reactance starting; (b) autotransformer starting; (c) wye-delta starting.

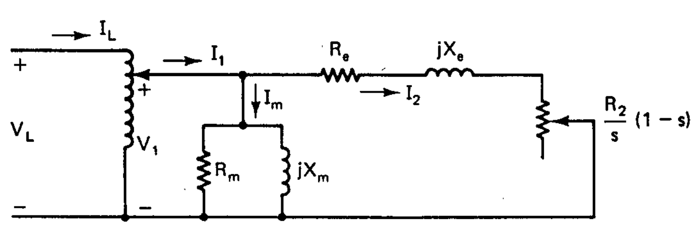

Figure 21: Circuit for autotransformer start of induction motor.

The applied voltage to the motor is

$$V_1 = 0.6(127) = 76.2 \text{ V/phase}$$

The input starting current is also 0.6 of its value from the previous example on motor starting current.

$$I_1 = 0.6(155.58\underline{/-57.92^o}) = 93.35\underline{/-57.92^o} \text{ A}$$

Similarly,

$$I_2 = 0.6(151.38\underline{/-78.93^o}) = 90.83\underline{/-78.93^o} \text{ A}$$

From Eq. 70 the input current to the autotransformer is

$$I_L = \frac{V_1 I_1}{V_L} = \frac{(76.2)(93.35\underline{/-57.92^o})}{127} = 56.01\underline{/-57.92^o} \text{ A}$$

This is only a little more than twice the rated running current of the motor, hence should not cause substantial voltage fluctuations.

The total motor losses will be

$$P_{\text{loss}} = \frac{3[(0.6)(57.07)]^2}{120} + 3(93.35)^2(0.30) + 3(90.83)^2(0.14) = 11,340 \text{ W}$$

which is $(0.6)^2 = 0.36$ of the losses during the full voltage start. This is still an order of magnitude greater than the operating losses at full load and would result in damage to the motor if it does not start within 10 to 20 seconds.

The total starting torque is

$$T_m = \frac{90(90.83)^2(0.14)}{\pi(1200)(1)} = 27.57 \text{ N}\cdot\text{m/rad}$$

which is about 46 percent of rated torque. If this torque is not adequate to start the motor load, then the autotransformer taps can be changed to provide a larger starting voltage of perhaps 0.7 or 0.8 times rated voltage, at the expense of larger line currents.

7 CAPACITY CREDIT

Wind generators connected to the utility grid obviously function in the role of fuel savers. Their value as a fuel saver may be quite adequate to justify their deployment, especially in utilities that depend heavily on oil fired generating plants. The value to a utility may be increased, however, if the utility could defer building some conventional generating plants because of the wind turbines presence on the grid. Wind generators would have to have some effective load carrying capability in order to receive such a capacity credit.

Some may feel that since the wind may not blow at the time of the yearly peak load that the utility is forced to build generation equipment to meet the load without considering the wind, in which case the wind cannot receive a capacity credit. This is not a consistent argument because any generating plant may be unavailable at the time of the peak load, due to equipment failure. The lack of wind is no different in its effect than an equipment failure, and can be treated in a standard mathematical fashion to determine the effective capacity of the wind generator.

One way of approaching the question of capacity credit is to consider the wind turbine as an alternative to other types of generation which might be installed by the utility. There is general agreement that the correct criterion for the economic selection of a generating unit is that its cost, when combined with the costs of other generating units making up a total electric utility generating system, should result in a minimum cost of electricity. The established method of checking this criterion is to simulate the total utility system cost over a period of time which represents a major fraction of the life of the unit being considered. The first step in this process is to define alternate expansions of the system capacity which will have equal reliability in serving the forecasted load. Annual production costs (fuel, operation and maintenance) are determined by detailed simulation methods. To these costs are added annual fixed charges on investment, giving total annual revenue requirements. The expansion having lowest present worth of revenue requirements is the economic choice. These economic terms will be discussed further in Chapter 8. The procedures of total utility system cost analysis have been understood and applied for many years, but tend to be complex, costly to use, and time consuming. There is thus a natural tendency to use shortcuts, at least in preliminary analyses.

One shortcut to the detailed simulation method which normally extends over 20 to 30 years is a detailed simulation for a single year. The effect of a changing mix of generation on future production costs can be approximately evaluated by selecting two years for detailed simulation, one at the beginning of the study period and the other at the end. This shortcut will normally give adequate results for preliminary analyses.

This simulation requires that we have a complete year of hourly wind data. This needs to be as typical as possible, which is difficult to determine because of the inherent variability of the wind. If the simulation results of one year suggest that the wind generator may be economically feasible, then perhaps nine other years of wind data need to be passed through the computer. The range of system yearly costs will help establish the actual economic feasibility of the wind generator. Such long time spans of good wind data collected at hub height, or at least 50 m, are not readily available, but are badly needed for these analyses.

Production costs for the simulation year are determined by standard utility techniques. Each generating plant is assigned a scheduled maintenance period. This is a period of typically 4 to 6 weeks each year for coal and nuclear plants, during which the plant is shut down, the turbine is taken apart and cleaned, and other routine and preventive maintenance is performed. These periods are normally scheduled during staggered periods in the spring and fall when the demand for electricity is relatively low.

Operation of the remaining units is scheduled on a chronological, hourly basis. The most economical plants are placed in service first and the least economical last. Nuclear plants have low fuel costs so are operated at maximum power as much as possible. Such plants which are operated a maximum amount are called *base load* plants. Base load coal units are scheduled next, followed by intermediate load and load following coal and oil fired units, which are followed by oil and gas fired peaking turbines. Generation with zero fuel cost, such as hydro and wind, is used as much as possible to reduce operating costs.

The utility bases its plans for expansion on the need to maintain a reliable system. Utilities try to maintain a total installed capacity at least 15 percent greater than the expected yearly peak load. This allows them to continue to meet the required load even if a large generating plant has a forced outage. When the load is not at its peak, several generating plants may have forced outages without affecting the ability of the utility to meet its load with its own generation.

There is a certain probability of a forced outage occurring during a daily operation cycle. This probability varies with the type, age, and general condition of the generating plant. A typical forced outage rate for a hydro plant may be 1.5 percent, while that of a coal fired plant may be 5 percent. A 5 percent forced outage rate means that, on the average, a given plant will be out of service at least a part of the day for one day out of twenty. Forced outages typically take the plant out of service for at least 24 hours before repairs are made and the plant is put back on the line, so the daily peak load would normally occur while the forced outage is present. This means that the daily peak is used in determining reliability of a system rather than hourly loads.

The probability of two generating plants being on forced outage at the same time is just the product of the probabilities that either one will be out. If each has a forced outage rate of 0.05, the probability of both being forced out at the same time is $(0.05)^2 = 0.0025$ or about 0.91 days per year. The probability of additional generation being out at this same time is still smaller, of course.

Suppose for the sake of illustration that we have a utility system with ten 700 MW generators, each with a forced outage rate of 0.05. Suppose that the load for several days is as shown in Fig. 22. The peak load for the first day is between 4900 and 5600 MW, so three generating plants have to be out of service before the utility is unable to meet its load. Two plants being out will cause a loss of load on the third day while four plants would have to be out on the fifth day to cause a loss of load. If the load ever exceeds 7000 MW then the probability of generation being inadequate that day is 1.0

Each day has a certain probability R_d (daily risk) that generation will be inadequate to meet the load. If we add these daily risks for an entire year, we get an annual risk R_a, expressed in days per year that generation will be inadequate[3].

$$R_a = \sum_{i=1}^{365} R_d(i) \tag{71}$$

Example

The daily peak load on the model utility system of Fig. 22 is between 3500 and 4200 MW for 150 days of the year, between 4200 and 4900 MW for 120 days, between 4900 and 5600 MW for 60 days, and between 5600 and 6300 for 35 days. What is the annual risk R_a?

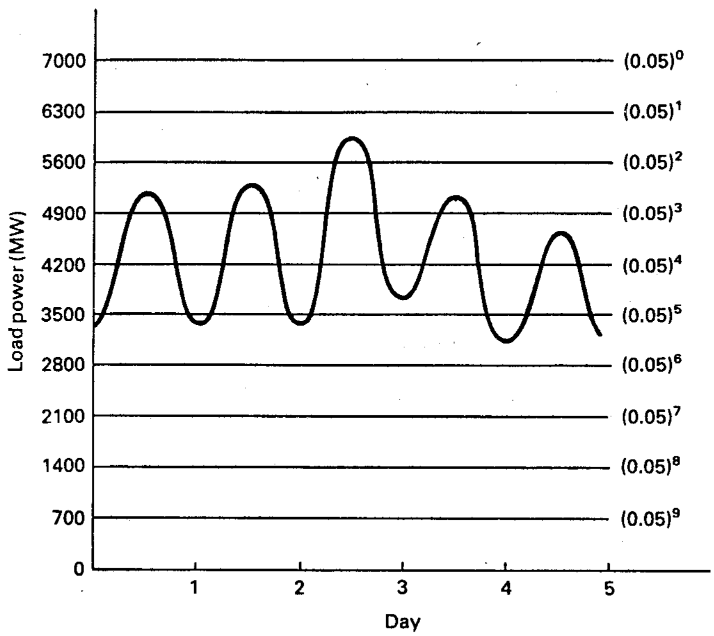

Figure 22: Load variation in model utility system.

$$
\begin{aligned}
R_a &= \sum_{i=1}^{365} R_d(i) = 150(0.05)^5 + 120(0.05)^4 + 60(0.05)^3 + 35(0.05)^2 \\
&= 4.6875 \times 10^{-5} + 7.5 \times 10^{-4} + 7.5 \times 10^{-3} + 87.5 \times 10^{-3} \\
&= 95.8 \times 10^{-3} = 0.0958 \;\text{ day per year}
\end{aligned}
$$

This result shows that generation is inadequate to meet load about 0.1 days per year or about one day in ten years. This level of reliability is a typical goal in the utility industry.

We see that a relatively small number of days with the highest peak load contributes the largest part of the annual risk. If these peaks could somehow be reduced through conservation or load management, system reliability would be improved.

It should be emphasized that even when load exceeds the rating of generators on a system, the utility may still meet its obligations by purchasing power from neighboring utilities or by dropping some less critical loads. Only when the generation of many utilities is inadequate will load actually be lost.

The effective capability or effective capacity of a proposed generating plant is determined in the following manner. The annual risk is determined for the original system for the year under investigation. This requires a loss-of-load probability calculation based on (1) the rating of each generating plant and its forced outage rate, (2) the daily hourly-integrated peak loads (the greatest energy sales in any one hour of the day), (3) maintenance requirements for each unit, and (4) other special features such as seasonal deratings or energy interchange contracts. The single point resulting from this calculation is spread out into a curve by varying the assumed annual peak load for that year by ±20 percent and each daily peak by the same fraction. As the assumed peak load increases for the same generation, the annual risk increases. A curve such as the original system curve of Fig. 23 is the result.

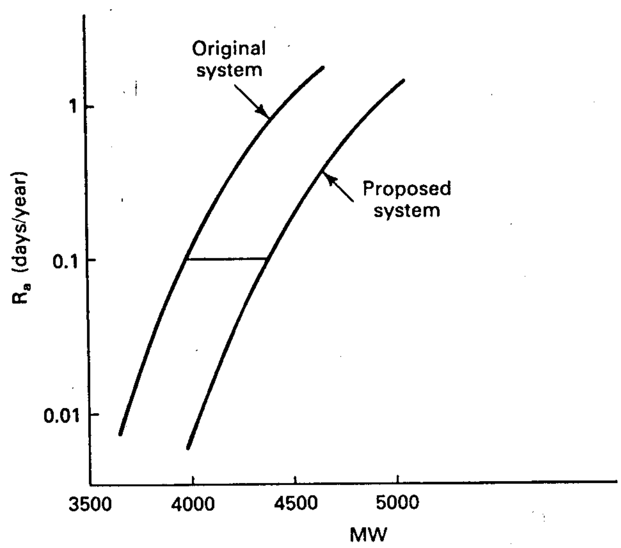

Figure 23: Annual risk before and after adding a new unit.

The proposed new generating plant is then added to the system while keeping all other data fixed. We again vary the annual peak load with the daily peaks considered as a fixed percentage of the annual peak. Adding this unit reduces the risk at a given load, so we consider a somewhat larger range of loads, perhaps a zero to 40 percent increase over the previous midpoint load. The result can be plotted into the second curve of Fig. 23. The distance in megawatts between these curves at the desired risk level is the amount of load growth the system can accept and still retain the same reliability. This distance is the effective capability or *effective capacity* of the new unit. The effective capacity will typically be between 60 and 85 percent of rated capacity for new fossil or nuclear power plants. If it is at 75 percent, this means that a 1000-MW generating plant will be able to support 750 MW of increased load. The remaining 250 MW will be considered reserve capacity.

The effective capacity is not identical to the capacity factor or plant factor, which was defined in Chapter 4 as the ratio of average power production to the rated power. Capacity factor is calculated independently of the timing of the load cycle, while effective capacity includes the effect of the utility hourly demand profile. Effective capacity may be either larger or smaller than the capacity factor. An oil fired gas turbine may have an actual capacity factor of less than 10 percent because of the limited hours of operation, but have an effective capacity of nearly 90 percent because of its high availability when the peak loads occur. Wind electric plants will almost always be operated when the wind is available because of the zero fuel cost. If the wind blows at the rated wind speed half the time and is calm the other half of the time, then the capacity factor would be 0.5 except for the reduction due to forced and planned outages. If the winds occurred at the times of the utility peaks, then the effective capacity would be close to unity. However, if the wind is calm when the utility peaks are occurring, the effective capacity will be near zero. The timing of the wind plant output relative to the utility hourly demand profile is critical.

General Electric has performed a large study to determine the effective capacity of wind turbines on actual utility systems[5]. They selected a site in Kansas, another in New York, and two in Oregon. Detailed data for Kansas Gas and Electric, Niagara Mohawk, and the Northwest Power Pool were analyzed using state-of-the-art computer programs. Actual load data and actual wind data were used. Results are therefore rather specific and somewhat difficult to extrapolate to other sets of circumstances. However, they represent the best possible estimate of capacity factor and effective capacity that could be obtained at the time of the study, and are therefore quite interesting.

Figure 24 shows the effective capacity and capacity factor for wind turbines on the assumed 1990 Kansas Gas and Electric System. Dodge City wind data for the years 1950, 1952, and 1953 were used in the study. These wind data were recorded at 17.7 m and extrapolated to hub height of a model 1500 kW horizontal axis, constant speed wind turbine by the one-seventh power law equation. A total wind generation capacity of 163 MW or 5 percent of total capacity was assumed. This is often referred to as a *penetration* of 5 percent. A forced outage rate of 5 percent was also assumed. There is no energy storage on the system.

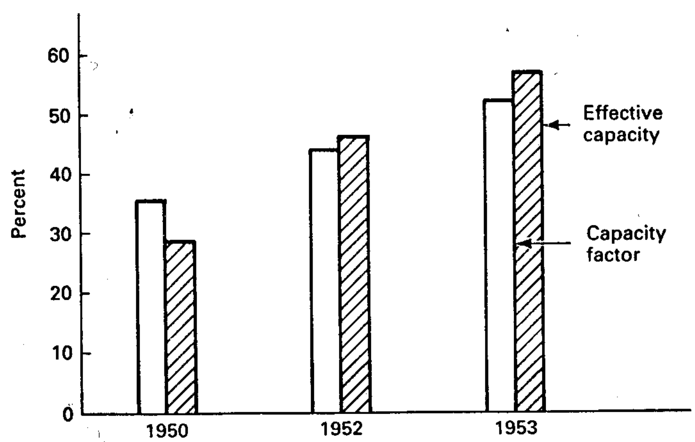

Figure 24: Impact of weather year on capacity factor and effective capacity.

It may be seen that effective capacity varies from less than 30 percent in 1950 to almost

60 percent in 1953. It can also be seen that the effective capacity is slightly larger than the capacity factor for two years and smaller for the third year. The particular year of wind data thus makes a substantial impact on the results. The representiveness of the year or years selected must therefore be considered before any firm conclusions are drawn.

The theoretical output of a MOD-0 located at Dodge City was determined for the years 1948 through 1973 in a attempt to determine the year-to-year variability[6]. The monthly energy production of each m^2 of turbine swept area is shown in Table 5.2 for each of the years in question, as well as the mean and standard deviation for all 26 years. The yearly standard deviation of 39.97 kWh/m^2 was computed from the yearly means rather than the sum of the monthly standard deviations. It may be seen that 1950 was two standard deviations below the mean. The only year worse than 1950 in this 26 year period was 1961 with 349.6 kWh/m^2. The year 1952 is close to the 26 year mean, but the summer months are somewhat above the mean, which tends to improve the effective capacity in this summer peaking utility. The year 1953 is about one standard deviation above the mean. The only year better than 1953 is 1964 with 518.8 kWh/m^2. We see that the three years selected cover the range of possible performance rather well. As more and better wind data become available, statistical limits can be defined with greater precision and confidence. In the meantime, for Dodge City winds, Kansas Gas and Electric loads, and a model 1500 kW wind turbine with 5 percent penetration, a reasonable estimate for capacity factor is a value between 35 and 50 percent. The corresponding estimate for effective capacity is between 30 and 55 percent of rated capacity. Other wind regimes and other load patterns may lead to substantially different results, of course.

The effective capacity of the wind plant tends to saturate as more and more of the utility generation system consists of this intermittent random power source. The study assumes that the wind is the same over the entire utility area (no wind diversity) so all the wind generators tend to act as a single generator. The utility needs to have enough generation to cover the loss of any one generator, so penetration levels above 15 or 20 percent of total system capacity would not have much effective capacity. Large amounts of storage would be required to maintain system reliability at higher penetration levels.

Figure 25 shows the variation in effective capacity with penetration for the four cases mentioned earlier. There is a wide variation, as might be expected, with Kansas Gas and Electric being the best and the Columbia River Gorge site of the Northwest Power Pool being the worst. The capacity factors for these two cases were almost identical, or about 45 percent for the wind years chosen. The reason for the low effective capacity at the Gorge site is that the bulk of the annual risk R_a is obtained from just a few days in the Northwest Power Pool, and the wind did not blow on those days in the particular wind year selected.

In a system like the Northwest Power Pool, wind diversity would be expected to improve the effective capacity, perhaps a significant amount. One test case showed that the combined output of wind turbines at both the Gorge and coast sites had a higher effective capacity than either site by itself. More computer studies are needed to determine the actual advantages of diversity.

Table 5.2 Theoretical Energy Production of MOD-0 Located at Dodge City (kWh/m^2)

	1950	1952	1953	Mean	Standard Deviation
Jan.	31.6	34.1	40.2	36.3	3.85
Feb.	29.5	35.0	41.8	37.5	3.60
Mar.	38.5	41.0	42.8	41.9	3.79
Apr.	36.0	39.4	43.1	42.3	4.41
May	37.4	33.9	44.3	40.3	4.50
Jun.	38.9	43.5	50.5	39.7	6.72
Jul.	26.8	41.5	38.2	35.3	6.40
Aug.	22.9	36.4	37.3	34.3	6.55
Sep.	24.3	37.1	37.2	37.2	4.58
Oct.	31.3	31.1	41.0	36.7	4.57
Nov.	28.2	36.4	37.9	35.1	5.39
Dec.	22.2	30.5	39.7	37.8	6.27
	367.7	440.1	493.8	454.4	39.97

It would appear from the limited data that effective capacities of wind turbines may vary from 10 to 60 percent for initial penetrations and from 5 to 45 percent at 5 percent penetration. Hopefully, wind diversity will raise the lower limit to at least 15 or 20 percent. We conclude, therefore, that wind turbines do have an effective capacity and that any complete cost analysis should include a capacity credit for the wind machines as well as a fuel savings credit.

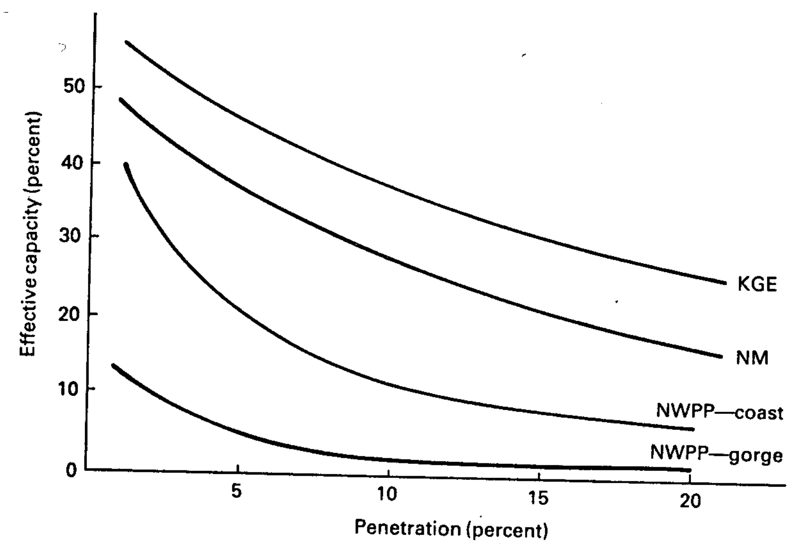

Figure 25: Wind power plant effective capacity versus penetration.

The actual capacity displaced, D_c, depends on the effective capacities of both the wind plant and the displaced conventional plant.

$$D_c = P_{eR}\frac{E_w}{E_c} \tag{72}$$

In this equation D_c is the displaced conventional capacity in kW or MW, P_{eR} is the rated power of the wind plant, E_w is the effective capacity of the wind plant, and E_c is the effective capacity of the conventional plant.

Example

A utility planning study shows that it needs to add 700 MW of coal fired generation to its system to maintain acceptable reliability. The effective capacity of this generation is 0.75. What nameplate rating of wind turbines with an effective capacity of 0.35 is required to displace the 700 MW of coal generation?

From Eq. 72,

$$P_{eR} = D_c\frac{E_c}{E_w} = 700\left(\frac{0.75}{0.35}\right) = 1500 \text{ MW}$$

For this particular situation, 1500 MW of wind generation is required to displace 700 MW of coal generation from a reliability standpoint. If, for example, the capacity factor of the coal generation was 0.7 and 0.4 for the wind generation, the wind turbines would produce more energy per year than the displaced coal plant. This means that less fuel would be burned at some existing plant, so the wind turbine may have both capacity credit and fuel saving credit. The utility system must meet both reliability and energy production requirements, so adding wind turbines to maintain reliability may force the capacity factors of other plants on the utility system to change. An example of the economic treatment of this situation is given in Chapter 8.

8 FEATURES OF THE ELECTRICAL NETWORK

The electrical network in which the wind electric generators must operate is a rather sophisticated system. We need to examine its organization so that we can better understand the interaction of the wind generator with the electric utility.

Figure 26 shows a one line diagram of a portion of an electric utility system. Power is actually transferred over three-phase conductors, but one line is used to represent the three conductors to make the drawing easier to follow. We start the explanation of this figure with the generating plant. This could be a large coal or nuclear plant, or perhaps a smaller gas or oil fired generator. The generation voltage is limited to about 25,000 volts because of generator insulation limitations. This is too low for long distance transmission lines, so it is increased through a step-up transformer to one of the transmission voltages for the particular utility. Some utilities use 115 kV, 230 kV, and 500 kV while others use 169 kV, 345 kV, and 765 kV. The higher voltage lines are used for transmitting greater power levels over longer distances.

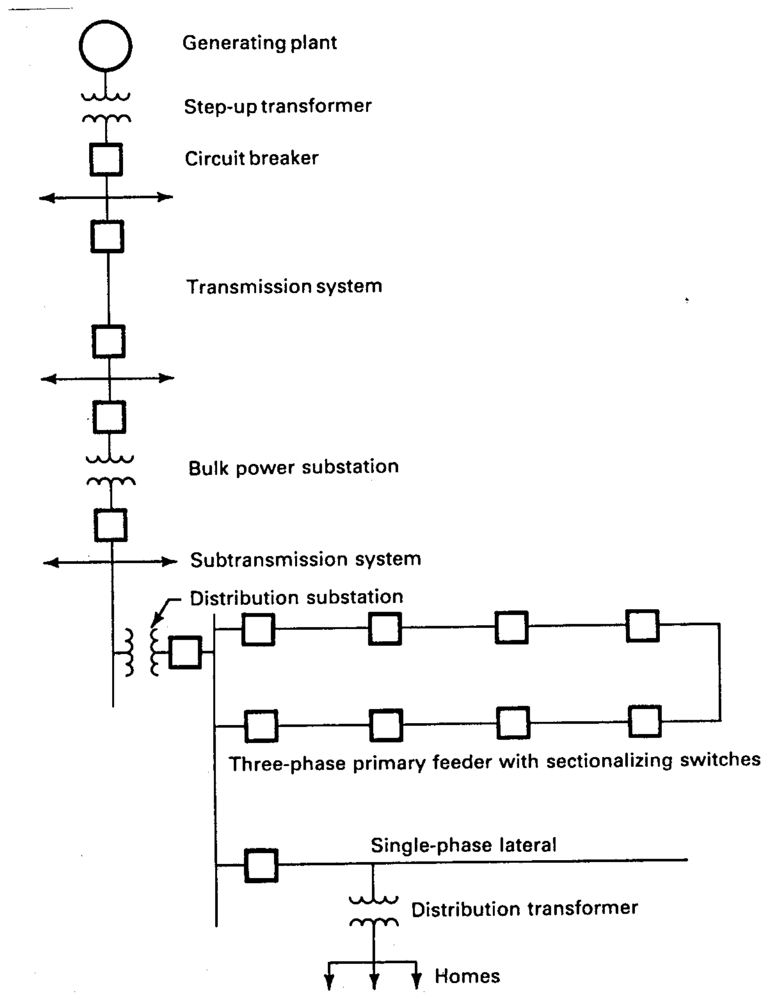

Figure 26: Typical electric utility system.

The next component shown in the one line diagram is a circuit breaker. This device is able to interrupt large current flows and protect the various system components from short circuits. If the short circuit were allowed to continue for a long period of time, even the transmission line would overheat and be destroyed. The circuit breaker is activated by protective relays which sense such parameters as voltage levels, current levels, frequency, and phase sequence on the power line.

The power flows through the transmission line until it reaches a bulk power substation. This is a collection of circuit breakers, switches, and transformers which connects the transmission line to several lines in the subtransmission system if the utility has such a system.

The power then flows to a distribution substation where it is stepped down to distribution voltages. The substation may feed a loop where every point in the loop can be reached from two directions. This organization allows most of the loads along such a primary feeder to be served even if a section of distribution line is not operable, due to storm damage, for example.

There will also be single-phase lateral or radial lines extending out from the distribution substation. These are connected to distribution transformers to supply 120/240 volts to homes along the line. These lines generally operate at voltages between 2.4 and 34.5 kV. These circuits may be overhead or underground, depending on the load density and the physical conditions of the particular area to be served. Substation transformer ratings may vary from as small as 1000 to 2500 kVA for small rural applications up to 50,000 or 60,000 kVA. Distribution transformer ratings are typically between 5 and 50 kVA.

The first responsibility of the design engineer is to protect all the utility equipment from faults on the system. These faults may be caused by lightning, storm damage, or equipment malfunction. When a fault occurs, line currents will be much larger than normal and a circuit breaker will open the line. A simple distribution substation protection scheme is shown in Fig. 27. The circuit breakers are adjusted so only the one nearest the fault will open. That is, if a fault occurs on the load side of circuit breaker CB4, only CB4 will open. The others will remain closed. Many of the circuit breakers in use are of the automatic reclosing variety, where the circuit breaker will automatically reclose after a fraction of a second. If the fault was caused by lightning, as it normally is, the electric arc between conductors will have time to dissipate while the breaker is open, so service is restored with minimum inconvenience to the customer. If the fault is still present when the breaker closes, it will open again, wait a fraction of a second, and close a second time. If the fault is still present, the breaker will open and remain open until the maintenance crew repairs the problem.

The larger transformers will be protected by differential current relays. This is a relay which compares the input and output current of a transformer and opens a breaker when the current ratio changes, indicating a fault within the transformer. There may be an underfrequency relay which will open a breaker if the utility frequency drops below some specified value. A number of other protective devices are used if required by the particular situation.

Once the system is properly protected, the quality of electricity must be assured. Quality refers to such factors as voltage magnitude, voltage regulation with load, frequency, harmonic content, and balance among the three phases. The electric utility goes to great lengths to deliver high quality electricity and uses a wide variety of methods to do so. We shall mention only the methods of controlling voltage magnitude.

The voltage in the distribution system will vary with the voltage coming in from the transmission lines and also with the customer load. It is adjusted by one or more of three possible methods. These are transformer load tap changing, voltage regulators, and capacitor banks. In the tap changing case, one of the transformer windings will have several taps with voltage differences of perhaps two percent of rated voltage per tap. The feeders can be connected to different taps to raise or lower the feeder voltage. This is done manually, perhaps on a seasonal basis, but can also be done automatically. Automatic systems allow the taps to

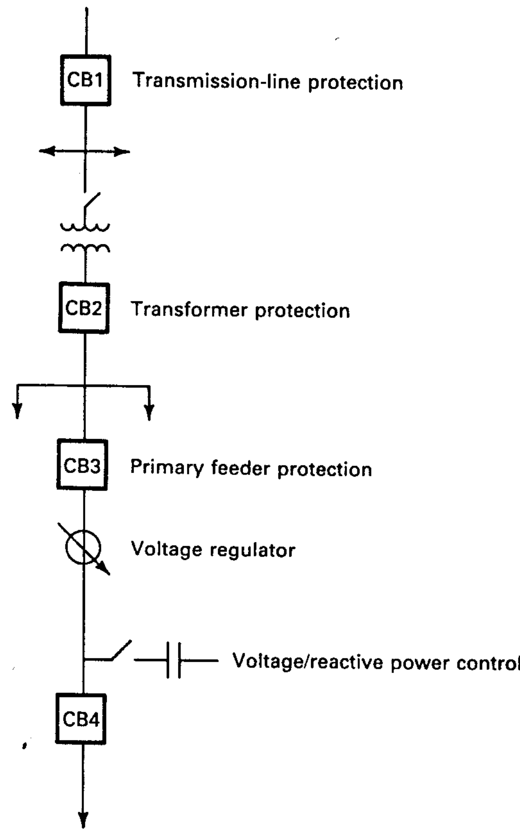

Figure 27: Distribution substation protection.

be changed several times a day to reflect changing load conditions.

The voltage regulator acts as an autotransformer with a motor driven wiper arm. This can adjust voltage over a finer range than the tap changing transformer and responds more rapidly to changes in voltage. It would be continually varying throughout the day as the loads change.

Capacitor banks are used to correct the power factor seen by the substation toward unity. This reduces the current flow in the lines and raises the voltage. They are commonly used on long distribution lines or highly inductive loads. They may be located at the substation but are often scattered along the feeder lines and at the customer locations. They may be manually operated on a seasonal basis or may be automatically switched in or out by a voltage sensitive relay.

All of these voltage control devices operate on the assumption that power flows from the substation to the load and that voltage decreases with increasing distance from the substation. A given primary feeder may have 102 percent of rated voltage at the substation and 98 percent at the far end, for example. This assumption is not necessarily valid when wind generators are added to the system. Power flow into the feeder is reduced and may even be reversed, in which case the line voltage will probably increase as one gets closer to the wind generator. We may have a voltage regulator that is holding the primary feeder voltage at 102 percent of rated, as before, but now the voltage at the far end may be 106 percent of rated, an unacceptably high value. It should be evident that wind generators can not be added to a distribution system without careful attention being given to the maintenance of the proper voltage magnitude at all points on the system.

We see in this simple example a need for greater or more sophisticated monitoring and control as wind generators are added to a power system. Existing power systems already have very extensive monitoring and control systems and these are becoming increasingly more complex to meet the needs of activities like load management and remote metering. We shall now briefly examine utility requirements for monitoring and control of their systems.

The structure of the power monitoring and control system in the United States is shown in Fig. 28. It can be seen that there are many levels in this system. At the top is the National Electric Reliability Council and the nine Regional Councils. These Regional Councils vary in size from less than one state (Electric Reliability Council of Texas (ERCOT)) to the eleven western states plus British Columbia (Western Systems Coordinating Council (WSCC)). Some of the Regional Councils function as a single power pool while others are split into smaller collections of utilities, covering one or two states. A *power pool* is a collection of neighboring utilities that cooperate very closely, both in daily operation of an interconnected system and in long range planning of new generation.

The reliability councils are primarily concerned with the long range planning and the policy decisions necessary to assure an adequate and reliable supply of electricity. They are usually not involved with the day to day operation of specific power plants.

Each power pool will have an operating center which receives information from its member utilities. This operating center will also coordinate system operation with other power pools.

Each large power plant will have its own control center. There may also be distribution dispatch centers which control the operation of substations, distribution lines, and other functions such as solar thermal plants, wind electric generators, storage systems, and load management, and gather the necessary weather data. Some utilities will not have separate distribution dispatch centers but will control these various activities from the utility dispatch center.

It should be mentioned that each utility is a separate company and that their association with one another in power pools is voluntary. The utilities will coordinate both the long term planning of new power plants and the day to day operation of existing plants with their neighbors in order to improve reliability and to reduce costs. Each utility tries to build enough generation to meet the needs of its customers, but there are periods of time when it is economically wise for one utility to buy electricity from another. If load is increasing by 100 MW per year and a 700-MW coal plant is the most economical size to build, a utility

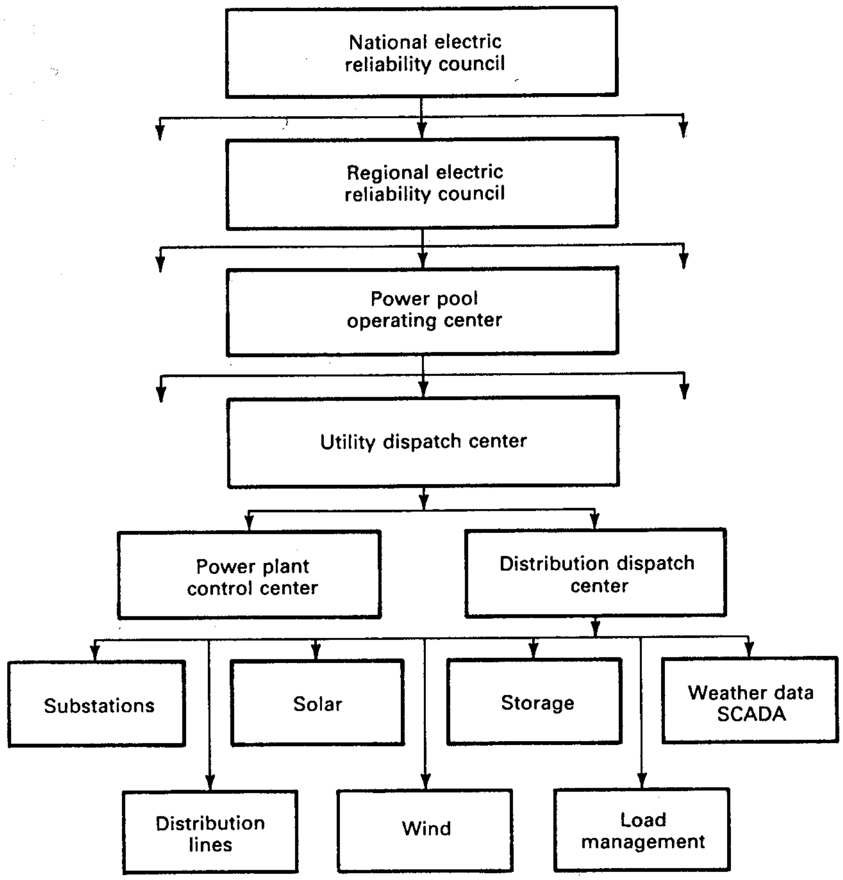

Figure 28: Monitoring and control hierarchy.

may want to buy electricity from another utility for two or three years before this coal plant is finished and then sell the surplus electricity for three or four years until the utility is able to use all of its capacity.

There are also times when short term sales are economically wise. One utility may have an economical coal plant that is not being used to capacity while an adjacent utility may be forced to use more expensive gas turbines to meet its load. The first utility can sell electricity to the second and the two utilities can split the cost differential so that both utilities (and their customers) benefit from the transaction. Such transactions are routinely handled by the large computers at the power pool operating center. Each utility provides information about their desire to buy or sell, and the price, to this central computer, perhaps once an hour. The computer then matches up the buyers and sellers, computes transmission line costs, and sends the information back to the utility dispatch centers so the utility can operate its system properly.

The power pool operating center will also receive status information on the large power plants and major transmission lines from the dispatch centers for emergency use. If a large power plant trips off line due to equipment malfunction, this information is communicated to all the utilities in the pool so that lightly loaded generators can be brought up to larger power levels, and one or more standby plants can be started to provide the desired spinning reserve in case another plant is lost. *Spinning reserve* refers to very lightly loaded generators that are kept operating only to provide emergency power if another generator is lost.

Power flows may also be coordinated between power pools when the necessary transmission lines exist. The southern states have a peak power demand in the summer while the northern states tend to have a winter peak, so power flows south in the summer and north in the winter to take economic advantage of this diversity.

Since the wind resource is not uniformly distributed, there may be significant power flows within and between power pools from large wind turbines. These power flows can be handled in basically the same way as power flows from other types of generation. The challenge of properly monitoring and controlling wind turbines is primarily within a given utility, so we shall proceed to look at this in more detail.

Most utilities have some form of *Supervisory Control And Data Acquisition* (SCADA) system. The SCADA system will provide the appropriate dispatch center with information about power flows, voltages, faults, switch positions, weather conditions, etc. It also allows the dispatch center to make certain types of adjustments or changes in the system, such as opening or closing switches and adjusting voltages.

The exact manner of operation of the SCADA system depends on the operating state of the power system. In general, a power system will be found in one of five states: normal, alert, emergency, in extremis, and restorative. The particular operating state will affect the operation of the wind generators on the system, so we shall briefly examine each state[1].

In the *normal* operating state, generation is adequate to meet existing total load demand. No equipment is overloaded and reserve margins for generation and transmission are sufficient to provide an adequate level of security.

The *alert* state is entered if the probability of disturbance increases or if the system security level decreases below a particular level of adequacy. In this state, all constraints are satisfied, such as adequate generation for total load demand, and no equipment is overloaded. However, existing reserve margins are such that a disturbance could cause overloads. Additional generation may be brought on line during the alert state.

A severe disturbance puts the system in the *emergency* state. The system is still intact but overloads exist. Emergency control measures are required to restore the system to the alert or to the normal state. If the proper action is not taken in time, the system may disintegrate.

When system disintegration is occurring, the power system is in the *in extremis* state. A transmission line may open and remove most of the load from a large generator. The generator speeds up and its over-frequency relay shuts it down. This may make other generation inadequate to meet load, with generators and transmission lines turning off in a domino fashion. Emergency control action is necessary in this state to keep as much of the system as possible from collapse.

In the *restorative* state, control action is taken to pick up lost load and reconnect the system. This can easily take several hours to accomplish.

System disintegration may result in wind generators operating in an island. A simple island, consisting of two wind turbines, two loads, and a capacitor bank used for voltage control in the normal state, is shown in Fig. 29. If the wind turbines are using induction generators, there is a good possibility that these generators will draw reactive power from the capacitor bank and will continue to supply real power to the loads. This can be a planned method of operating a turbine independently of the utility system, as we shall see in the next chapter. Without the proper control system, however, the voltage and frequency of the island may be far away from acceptable values. Overvoltage operation may damage much of the load equipment as well as the induction generators themselves. Frequencies well above rated can destroy motors by overspeed operation. Under frequency operation may also damage motors and loads with speed sensitive oiling systems, including many air conditioning systems.

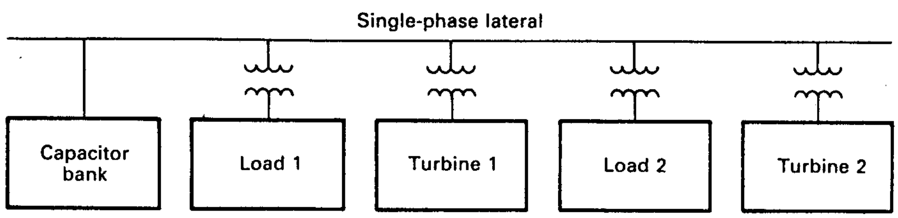

Figure 29: Electrical island.

In addition to the potential equipment problems, there is also a safety hazard to the utility linemen. They may think this particular section of line is dead when in fact it is quite alive. In fact, because of the self-excitation capability of the induction generator, the line may change from dead to live while the linemen are working on it, if the wind turbines are not placed in a stop mode.

All of these problems can be handled by proper system design and proper operating procedures, but certain changes in past operating procedures will be necessary. In the past, the control, monitoring, and protection functions at a distribution substation have generally been performed by separate and independent devices. Information transfer back to the dispatch center was very minimal. Trouble would be discovered by customer complaints or by utility service personnel on a regular maintenance and inspection visit to the substation. An increasing trend is to install SCADA systems at the substations and even to extend these systems to the individual customer. A SCADA system will provide status information to the dispatcher and allow him to make necessary adjustments to the distribution system. At the customer level, the SCADA system can read the meter and control interruptible loads such as hot water heaters. Once the SCADA system is in place, it is a relatively small incremental step to measure the voltage at several points along a feeder and adjust the voltage regulator accordingly. This should minimize the effect of wind generators on the distribution lines.

At the next level of control, the larger wind electric generators will have their own computer control system. This computer could be intertied with the SCADA system so the utility dispatcher would know the wind generator's power production on a periodic basis. It would be desirable for the dispatcher to be able to shut the wind turbine down if a severe storm was approaching the turbine, for example. It would also be desirable for the dispatcher to be able to shut the turbine down in emergency situations such as islanding. There may also be times when the utility cannot effectively use the wind power produced that the dispatcher would also want to turn the turbine off. This would normally occur late at night when the electrical demand is at its minimum and the large steam turbine generators on the utility system have reached their minimum power operating point. The large generators will be needed again in a few hours but have to operate above some minimum power in the meantime. Otherwise they have to be shut down and restarted, a potentially long and expensive operation. It would be more economical for the utility to shut down a few wind turbines for a couple of hours than to shut down one of their large steam units.

The division of computer functions between the dispatch center and a wind turbine presents a challenge to the design engineer. As much local control as possible should be planned at the wind turbine, to improve reliability and reduce communication requirements. One possible division of local and dispatcher control is shown in Table 5.3. At the wind turbine is the capability to sense wind conditions, start the turbine, shut it down in high winds, synchronize with the utility grid, and perhaps to deliver acceptable quality power to an electrical island or an asynchronous load. There are also sensors and a communication link to supply information to the dispatch center on such things as operating mode (is the turbine on or off?), power flow, voltage magnitude, and the total energy production for revenue metering purposes. The dispatch center will examine these parameters on a regular basis, perhaps once an hour, and also immediately upon receipt of an alarm indication. The dispatch center may also be able to turn the turbine on or off, or even to change the power level of a sophisticated variable-pitch turbine.

The benefits of such two-way communication and control can be significant. It can improve system reliability. It can also improve operating economics. It may even be able to control operation of electrical islands. Certainly, it will help to reduce equipment losses from system faults, and to improve the safety of maintenance operations.

The costs can also be quite significant. A utility considering a new distribution dispatch center can expect the building, interfaces, displays, information processors, and memory to an installed cost of at least $700,000 in 1978 dollars[2]. A FM communications tower which can service an area of 30 to 40 km in radius would cost another $50,000. At each wind generator, the cost of communications equipment, sensors, and control circuitry could easily exceed $10,000. This does not include the circuit breakers and other power wiring.

TABLE 5.3 Communication and Control between a Large Wind Turbine Generator and a Dispatch Center

Under Local Control
(a) Start Capability
(b) Synchronization
(c) Stand-Alone Capability
(d) Protection
Information to Dispatch Center
(a) Operating Mode (on/off)
(b) Power Flow
(c) Voltage Magnitude
(d) Revenue Metering
Control from Dispatch Center
(a) Change Operating Mode
(b) Change Power Level

If there were 75 wind turbines being monitored and controlled by the dispatch center, and all the dispatch center costs were to be allocated to them, each wind turbine would be responsible for \$10,000 of equipment at the dispatch center and another \$10,000 of equipment at the turbine. This \$20,000 would present a major obstacle to the purchase of a 5 kW wind generator priced at \$8000, but not nearly as much of an obstacle to a 2.5 MW wind generator priced at \$2,000,000. In one case the monitoring and control equipment cost 2.5 times as much as the wind generator itself, and only 1 percent of the wind generator cost in the second case. This is another economy of scale for wind generators. In addition to turbine cost per unit area decreasing with size, and power output per unit area increasing with size because of greater height and therefore better wind speeds, the cost of monitoring and control per unit area also decreases with turbine size.

The probable result of these economic factors is that small wind generators, less than perhaps 20 kW maximum power rating, will not be monitored and controlled by a dispatch center. Each small wind generator will have its own start, stop, and protective systems. The utility will somehow assure itself that voltage magnitudes are within acceptable limits and that electrical islands cannot operate on wind power alone and continue to operate the system in a manner much like the past. This should be satisfactory as long as the total installed wind generator capacity is significantly less than the minimum load on a feeder line.

On the other hand, large wind turbines will almost certainly be monitored and controlled by the appropriate dispatch center. This control can result in significant benefits to both the utility and the wind turbine, with acceptable costs.

9 PROBLEMS

1. In the circuit of Fig. 30, the applied single-phase voltage is 250 V and the frequency is 60 Hz. The magnitude of the current in the series RL branch is $|I_2| = 10$ A.

   (a) What is the real power supplied to the circuit?
   (b) What is the net reactive power supplied to the circuit? Is it positive or negative?
   (c) What is the power factor of the circuit and is it leading or lagging?

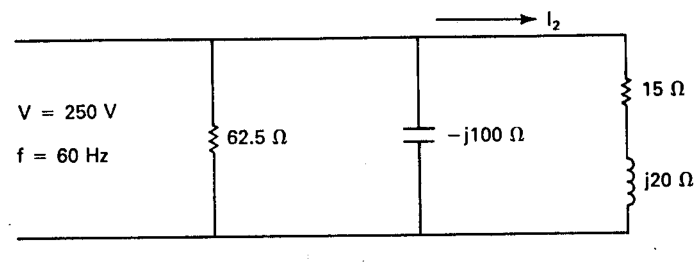

Figure 30: Circuit diagram for Problem 1.

2. In the circuit of Fig. 31, a total real power of 4000 W is being supplied to the single-phase circuit. The input current magnitude is $|I_1| = 8$ A.

   (a) Find $|I_2|$.
   (b) Find $|V_2|$.
   (c) Assume that $V_2 = |V_2|\underline{/0^o}$ and draw V_2, I_2, I_c, and I_1 on a phasor diagram.
   (d) Determine X_C.

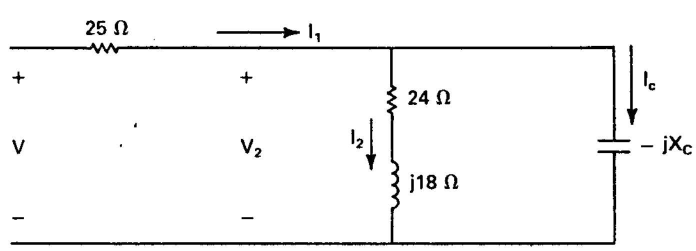

Figure 31: Circuit diagram for Problem 2.

3. A load connected across a single-phase 240-V, 60-Hz source draws 10 kW at a lagging power factor of 0.5. Determine the current and the reactive power.

4. A small industry has a number of induction motors which require a total apparent power of 100 kVA at a lagging power factor of 0.6. It also has 20 kW of resistance heating. What is the total apparent power required by the industry and what is the overall power factor?

5. A single-phase generator supplies a voltage E to the input of a transmission line represented by a series impedance $Z_t = 1 + j3\ \Omega$. The load voltage V is 250 $\underline{/0^o}$ V. The circuit is shown in Fig. 32.

   (a) With switch S_1 open, calculate the current I_1, and the real power, reactive power, and power factor of the load.
   (b) Calculate the generator voltage E.
   (c) Calculate the power lost in the transmission line.
   (d) With switch S_1 closed and the voltage V remaining at $250\underline{/0^o}$, find the capacitor current I_c, the new input current I_1, and the new overall power factor.
   (e) Calculate the new generator voltage and the new transmission line power loss.
   (f) List two advantages of adding a capacitor to an inductive load.

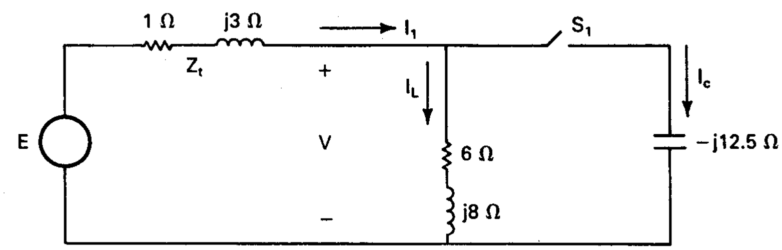

Figure 32: Circuit diagram for Problem 5.

6. A three-phase load draws 250 kW at a power factor of 0.707 lagging from a 440-V line. In parallel with this load is a three-phase capacitor bank which draws 60 kVA. Find the magnitude of the line current and the overall power factor.

7. A wind turbine of the same rating as the MOD-1 has a synchronous generator rated at 2000 kW (2500 kVA at 0.8 power factor) at 4160 V line to line. The machine impedance is $0.11 + j10\Omega$/phase. The generator is delivering 1500 kW to a load at 0.9 power factor lagging. Find the phasor current, the phasor generated voltage E, the power angle δ, the total pullout power, and the ohmic losses in the generator stator.

8. The field supply for the machine in the previous problem loses a diode. This causes $|E|$ to decrease by 10 percent. Real power being delivered to the utility grid is determined by the wind power input and does not change. What is the new power angle δ and the new total reactive power being supplied to the utility grid?

9. A 500-kW Darrieus wind turbine is equipped with a synchronous generator rated at 480 V line to line and 625 kVA at 0.8 power factor. Rated current is flowing and the current leads the voltage by 40^o. What are the real and reactive powers being supplied to the load?

10. A MOD-OA generator is rated at 250 kVA, 60 Hz, and 480 V line to line. It is connected in wye and each phase is modeled by a generated voltage E in series with a synchronous reactance X_s. The per unit reactance is 1.38. What is the actual reactance per phase? What is the actual inductance per phase?

11. The generator in the previous problem is connected to a circuit with a chosen base of 1000 kVA and 460 V. Find the per unit reactance on the new base.

12. A three-phase induction generator is rated at 230 V line to line and 14.4 A at 60 Hz. Find the base impedance, the base inductance, and the base capacitance.

13. A 11.2-kW (15 hp), 220-V, three-phase, 60-Hz, six-pole, wye-connected induction motor has the following parameters per phase: $R_1 = 0.126\ \Omega$, $R_2 = 0.094\ \Omega$, $X_1 = X_2 = 0.248\ \Omega$, $R_m = 92\ \Omega$, and $X_m = 8\ \Omega$. The rotational losses are accounted for in R_m. The machine is connected to a source of rated voltage. For a slip of 2.5 percent find:

    (a) The line current and power factor.
    (b) The power output in both kW and hp.
    (c) The starting torque ($s = 1.0$).

14. A three-phase, 440-V, 60-Hz, eight-pole, wye-connected, 75-kW (100-hp) induction motor has the following parameters per phase: $R_1 = 0.070\ \Omega$, $R_2 = 0.068\ \Omega$, $X_1 = X_2 = 0.36\ \Omega$, $R_m = 57\ \Omega$, and $X_m = 8.47\ \Omega$. For a slip of 0.03 determine the input line current, the power factor, and the efficiency.

15. A three-phase, 300-kW (400-hp), 2000-V, six-pole, 60-Hz, wye connected squirrel-cage induction motor has the following parameters per phase that are applicable at normal slips: $R_1 = 0.200\ \Omega$, $X_1 = X_2 = 0.707\ \Omega$, $R_2 = 0.203\ \Omega$, $X_m = 77\ \Omega$, and $R_m = 308\ \Omega$. For a slip of 0.015 determine the input line current, the power factor, the torque, and the efficiency.

16. The induction machine of the previous problem is operated as a generator at a slip of -0.017. Find I_1, I_2, input mechanical power, real and reactive power, and the efficiency. Comment on any overload.

17. An autotransformer is connected to the motor of problem 7 for starting. The motor voltage is reduced to 0.7 of its rated value. Find the motor starting current, the line current at start, and the starting torque. Note that $s = 1$ at start.

18. The model utility system of Fig. 22 implements a massive conservation and load management program which reduces the daily peak load an average of 700 MW. Compute the new annual risk R_a, assuming the same 7000 MW of generation as in Fig. 22.

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