CAPACITOR APPLICATION ISSUES

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Abstract - Capacitors provide well-known benefits to electric power systems. These benefits include power factor correction, voltage support, release of system capacity, and reduced system losses. As with any piece of electrical equipment, there are a number of application issues that engineers need to be aware of. These issues range from the very basic to the very complex.

Most of these application issues can be, and have been, the subject of their own detailed technical papers. This paper does not get into rigorous detail but rather discusses these issues with the goal of making the reader aware of many of the traps one can fall into when applying capacitors.

The application issues are addressed based on the authors' experiences working in various capacities (performing power system measurements and studies, performing engineering service failure investigations, advising capacitor sales personnel, consulting with end users, and building custom capacitor banks), thus seeing these problems from many different angles.

Index Terms - capacitors, power factor, demand, penalties, filters, harmonics, resonance, transients.

I. CAPACITOR SIZING

A. Power Factor Definition

Even the most basic capacitor application question, how much capacitance is needed, is not as simple as it first appears. This is because electric utility power factor penalties vary considerably and power factor is not calculated consistently from utility to utility.

In order to calculate the required amount of capacitance to raise the present system power factor to a specified higher power factor, several pieces of information are needed: the kVA or kW and power factor of the existing load, and the target/desired power factor. The difficulty comes from the fact that we can calculate power factor in different ways, and these different ways affect how much capacitance we need to apply in a given situation. Note that this discussion is focused on simple 60 Hz power factor calculation; we are not delving into more esoteric considerations such as harmonic power flow, distortion power, and such.

Some utilities calculate power factor as an average during the 15 (or 30) minute interval coincident with the peak kW or kVA demand, depending on how the utility bills for peak demand. Other utilities accumulate kWh (kilowatt-hours) and kvarh (kvar-hours) over the course of the month, in effect calculating an average power factor over the entire month. In the former case, one would use the power factor and the peak kW or kVA during the demand interval to do the required kvar calculation. In the latter, one would use the accumulated kWh and kvarh to first calculate the required kvarh of correction needed over the month, and then divide out the hours in the month to get the required capacitor bank size.

In most real-world cases, power factor correction calculations based on peak kW/kVA and power factor in a short demand interval will require a larger capacitor bank to correct the power factor than the accumulated kWh and kvarh over a month method. This is because the kvar calculation is done at peak load, even if the power factor during that interval may not be as low as at periods of lighter load.

The reason that a power factor correction calculation based on accumulated kWh and kvarh generally results in a lower required capacitor size for correction is that you do not need to meet the target power factor at any particular point in time or during any particular demand interval. It is okay, for instance, if you do not meet the target power factor during the middle of the day, when loads are typically highest, as long as you exceed the target power factor at other times, typically at night when loads are lower.

In the extreme case, one can meet the target power factor by running a leading power factor at times (sending vars back the utility), in effect turning the kvarh meter backwards. Some utilities allow this. It is more common for utilities using this type of contract (accumulated kWh and kvarh) to not give credit for leading power factor. A utility may state in its rate that the power factor shall be determined by the kWh and lagging kvarh accumulated over the month—note the exclusion of leading kvarh. One utility explicitly states, "A device will be installed on each kilovar meter to prevent reverse operation of the meter."

Regardless of whether leading kvarh are credited, with power factor calculated by accumulating kWh and kvarh over the month one can make up for being below the target power factor at some times by being above the target power factor at other times. This may allow one to choose a smaller fixed capacitor, as opposed to a larger, switched capacitor bank.

It is not practical to cover all the possible variations on how power factor might be calculated; there is an exception to every rule. The point is that engineers should be aware that the way power factor is calculated affects the required kvar calculation. Engineers should read the electric utility's published rate to determine how power factor is calculated and take this into account.

B. Month-by-Month Calculations versus Averaging

Another source of error when calculating the required kvar needed to correct poor power factor is relying too much on averages, maxima, and minima. It is always a good idea to gather a number of past power bills when doing power factor correction analysis. This is because load levels vary over the course of a year and you would want to choose the amount of capacitance needed based on a worst case month.

The problem is that some people try to summarize these multiple months of data in order to do just one power factor calculation. Table 1 shows some power factor calculations done on a month-by-month (each month calculated separately) basis. Table 2 shows the monthly data summarized before doing the power factor calculations. Typically one would choose the average or maximum kW load and the average or minimum power factor. The results show that you can end up buying a much larger capacitor bank than necessary using this approach.

Calculations should be done on a month-by-month basis. The largest capacitance needed in an individual month would then be selected, say 600 kvar based on the results from Table 1. It may seem time-consuming to do multiple power factor calculations by hand. However, with a spreadsheet program such as Microsoft Excel it is easy to do a number of these calculations very quickly.

An additional benefit of doing these calculations in a spreadsheet is that other calculations of interest can be incorporated. Such calculations might include no-load voltage rise with fixed capacitors and the resonant harmonic frequency of the system when capacitors are added (if the user inputs certain system information, including source transformer kVA and percent impedance).

TABLE 1

EXAMPLE POWER FACTOR CALCULATIONS, USING MONTHLY DATA, .95 PF TARGET

kW	PF	kvar Needed
1200	.78	583.8
1000	.83	343.3
1100	.80	463.4
950	.73	577.2
700	.65	588.3
850	.70	587.8

TABLE 2

EXAMPLE POWER FACTOR CALCULATIONS, USING SUMMARIZED DATA, .95 PF TARGET

Maximum kW	Minimum PF	kvar Needed
1200	.65	1008.5
Maximum kW	**Average PF**	**kvar Needed**
1200	.75	671.9
Average kW	**Minimum PF**	**kvar Needed**
966.7	.65	812.4
Average kW	**Average PF**	**kvar Needed**
966.7	.75	541.3

II. POWER FACTOR PENALTIES

It is not the intention of this paper to discuss power factor penalties in detail but rather to present an overview so that the reader will have a basis to investigate their utility bill. Table 3 shows a number of different types of power factor penalties. Most are straightforward and can be analyzed by engineers and end users to help determine how to reduce power factor penalties. Sometimes utilities will incorporate multiple methods of billing for low power factor, so several of the penalties in Table 3 may be applied.

Sometimes a power factor penalty is somewhat hidden. For example, in a straight kVA demand rate there is nothing that explicitly mentions a power factor penalty. But a poor power factor will result in a higher kVA for a given kW of load, so there is an implicit power factor penalty built into that rate. In other cases the utility may give a rebate for maintaining a power factor above a given level. At a glance you might not think you are paying a penalty if you do not get this rebate. But you would be leaving money on the table if you did not take advantage of the rebate. It is functionally equivalent to a power factor penalty, just phrased differently.

Note that for most of these rates it is not practical to correct all the way to unity power factor. First of all, further improvement (above a power factor threshold level) costs more. Even if there is a unity power factor target (e.g. kVA billing), going closer to unity may cost more to achieve than will be saved. This could result in higher absolute dollars saved but a lower rate of return on the project (due to the higher initial investment). Secondly, going all the way to unity might require a switched capacitor bank, whereas applying a lesser amount of capacitance reduces the possibility of leading power factor (for which some utilities also penalize), or at least minimizes how far leading the power factor will go.

III. CAPACITOR RATINGS

Capacitors must be built to tolerate voltages and currents in excess of their ratings according to standards. The applicable standard for power capacitors is IEEE Std 18-2002, *IEEE Standard for Shunt Power Capacitors*. Additional information is given in IEEE Std 1036-1992, *IEEE Guide for Application of Shunt Power Capacitors*.

IEEE Std 18-2002 gives the following continuous overload limits. These are "intended for contingencies and not intended to be used for a nominal design basis." [15]

- 110% of rated rms voltage
- 120% of rated peak voltage
- 135% of rated rms current (nominal current based on rated kvar and voltage)
- 135% of rated reactive power

Short time overload voltages were specified in IEEE Std 18-1992 (on older version of the standard) and IEEE Std 1036-1992 and are listed below. These standards state that a capacitor may be expected to see a combination of 300 such overvoltages in its service life. Note that these overvoltages are "…without superimposed transients or harmonic content."

- 2.20 per unit rms voltage for 0.1 seconds
  (6 cycles of rms fundamental frequency)
- 2.00 per unit rms voltage for 0.25 seconds
  (15 cycles of rms fundamental frequency)

TABLE 3

POWER FACTOR PENALTIES

RATE TYPE	DESCRIPTION OF PF PENALTY	EXAMPLE
kVA (demand) rates	Penalty for < 1.0 pf; generally applied as a $/kVA	Demand = 800 kW; pf=80%; kVA=1000; demand charge = $10/kVA pf penalty = (1000 – 800)*$10 = $2000/month
PF (kVA) adjustment	When the pf is less than X%, the demand may be taken as X% of the measured kVA	When the pf is less than 90%, the demand may be taken as 90% of the measured kVA pf=80%; kVA=1000; demand charge = $10/kVA Billed demand = 0.90*1000 = 900 kW pf penalty = (900 – 1000*0.80)*$10 = $1000/month
PF ratio (kW demand) adjustment	If the pf is < X%, the demand will be adjusted by the following: X%/actual pf * actual demand = adjusted demand.	If the pf is < 85%, the demand will be adjusted by the following: 85%/actual pf * actual demand = adjusted demand. Demand = 800 kW; pf=80%; demand charge = $10/kW Adjusted demand = (0.85/0.80)*800=850kW pf penalty = (850-800)*$10 = $500/month
PF magnitude (kW demand) adjustment	PF adjustment increases or decreases the net (kW) demand charge X% for each Y% the pf is above or below the utility specified pf	Where the pf is < 85%, the net demand charges shall be increased 1% for each whole 1% the pf is < 90%; likewise, where the pf is higher than 95%, the demand charges will be reduced by 1% for each whole 1% the pf is above 90%. Demand = 800 kW; pf=80%; demand charge = $10/kW Up to 90%, demand adjustment = 800*10%=80kW (from 80% to 90%) = net demand of 880 kW If pf is corrected to 1.0, pf adjustment (reduction) = 800*10%=80kW (from 90%-100%) = net demand of 720kW Correcting pf from 80% to 100%, potential net savings is (880-720)*$10/kW = $1600/month
PF multiplier (PFM)	Demand is increased (or decreased) by a calculated multiplier determined by a utility table or by a formula	Demand = 800 kW; pf=80%; PFM = 1.086; demand charge = $10/kVA pf penalty = 800*$10*(0.086) = $688/month
kvar demand charge	$X per kVA of reactive demand in excess of Y% of the kW demand	$0.45 per kVA of reactive demand in excess of 50% of the kW demand Demand = 800 kW; pf=80%; kvar demand = 600; excess kvar demand = 600 – 800*0.50 = 200 kvar pf penalty = 200 kvar*($0.45/kvar) = $90/month
kvarh charge	$X per kvarh	$0.000835 per kvarh kvarh = 500,000 pf penalty = 500,000*0.00835 = $417/month
kWh adjustment (note that this often applies where the kW demand is first adjusted)	$P/kWh for first Q*kWh*demand $R/kWh for next S*kWh* demand $X/kWh for next Y*kWh demand $Z/kWh for all additional	$0.040/kWh for first 100 kWh*demand $0.035/kWh for next 150kWh*demand $0.025/kWh for next 150kWh*demand $0.020/kWh for all additional kWh Actual demand = 800 kW; Adjusted demand = 1000 kW; kWh measured = 500,000 With penalty 100*1000=100,000 kWh @ 0.04/kWh=$4000 150*1000=150,000 kWh @ 0.035/kWh=$5250 150*1000=150,000 kWh @ 0.025/kWh=$3750 (500,000-100,000-150,000-150,000)*$0.02/kWh = $2000 Total = $15,000 Without penalty 100*800=80,000 kWh @ 0.04/kWh=$3200 150*800=120,000 kWh @ 0.035/kWh=$4200 150*800=120,000 kWh @ 0.025/kWh=$3000 (500,000-80,000-120,000-120,000)*$0.02/kWh = $3600 Total = $14,000 Penalty = $15,000 - $14,000 = $1,000/month (in addition to demand penalty)

- 1.70 per unit rms voltage for 1 second
- 1.40 per unit rms voltage for 15 seconds
- 1.30 per unit rms voltage for 1 minute
- 1.25 per unit rms voltage for 30 minutes

An even older version of the standard, IEEE Std 18-1980, also included the following permissible overvoltages.

- 3.00 per unit rms voltage for 0.0083 seconds (½ cycle of rms fundamental frequency)
- 2.70 per unit rms voltage for 0.0167 seconds (1 cycle of rms fundamental frequency)

It should be noted that some capacitor manufacturers make heavy duty capacitors particularly for industrial environments. One manufacturer makes the following claims about its heavy duty capacitors in its literature. "...they are designed to exceed the requirements of these [ANSI/IEEE, NEMA, and IEC] standards in terms of continuous rms and peak overvoltage withstand capabilities, and in tank rupture characteristics." This manufacturer rates the continuous overvoltage capability at 125% (as opposed to 110%) and its continuous peak overvoltage capability at 135% (as opposed to 120%).

When doing power system studies it is important to compare the measured or calculated voltages or currents against these ratings. In different study cases, different ratings will apply. For example, harmonics are a steady-state phenomenon so the continuous limits would need to be considered. However, voltage harmonics resulting from a relatively short term event, such as transformer energization inrush, might be compared against the short time overload ratings.

One of the interesting implications of these overvoltage allowances is that capacitors can be applied at voltages in excess of their ratings for very short periods of time. Why would one do this? The main reason is because the kvar produced by a capacitor is related to the square of the voltage ratio. For example, a capacitor applied at a voltage 40% higher than its nameplate will produce double its nameplate kvar.

Capacitor motor starting is one application where this is done. Large medium voltage motors, possibly applied on relatively weak power systems, sometimes cause an excessive voltage drop during motor starting. When a motor starts, it draws a large amount of reactive current. Capacitor motor starting is the practice of momentarily switching on a capacitor bank for a short time during motor starting, to compensate for the reactive current draw, allowing the motor to start successfully without causing excessive voltage drop. Since the capacitors are only on-line momentarily, they can be significantly underrated. This takes advantage of the momentary overvoltage capabilities that capacitors must meet by industry standards. By underrating the capacitors, the reactive power (kvar) output of the capacitor bank is significantly increased. Note that capacitors sized for power factor correction do not provide nearly enough kvar to significantly aid motor starting.

Users should be aware that capacitor overvoltage capability was not intended for everyday use but rather for contingency use. If the motors are switched daily, or harmonics or transients are present, or the capacitors occasionally are on line without load and the feeder voltage rises, the life of the capacitor will be shortened. Operations personnel should strive to minimize such motor starts to maximize capacitor life.

The conclusion is that capacitor motor starting is a perfectly legitimate method to aid the starting of large motors. But it must be realized that these capacitors may experience a reduced service life. Despite this reduced life, capacitor starting may still be an economical alternative.

IV. Code Requirements and Protection

A. NEC Article 460

The National Electric Code (NEC) [1] provides guidance in the installation and protection of power capacitors in Article 460. This section of the paper discusses selected items from NEC Article 460, and focuses mainly on low voltage capacitors. The reader is encouraged to consult this article for more information. For example, although not discussed in this paper, there are significant requirements for applying capacitors on motor terminals.

B. Conductor and Disconnect Sizing

NEC Article 460.8 (A), for low voltage capacitors, states:

> The ampacity of capacitor circuit conductors shall not be less than 135 percent of the rated current of the capacitor.

NEC Article 460.8 (C) (3), for low voltage capacitors, states:

> The rating of the disconnecting means shall not be less than 135 percent of the rated current of the capacitor.

Capacitors can draw more than their rated current during overvoltage conditions. They also tend to be an attractive path for harmonic currents, which boost the rms current.

Note also that capacitors are not like typical power system loads that have some diversity (not on all the time). A fixed capacitor bank will draw full load current continuously. Even an automatically-switched capacitor bank can switch on and stay fully on for most of the day.

There is another reason to oversize the wire serving a capacitor bank. It is not practical to set overcurrent protective devices tightly enough to protect against overloads. Capacitor switching transients will result in excessive nuisance trips if protection is set too closely to the capacitor nominal current. Without such overload protection, it is important that the wires be sized to tolerate overloads. The overcurrent protection section, next, discusses this further.

C. Overcurrent Protection

There are two purposes for the fuses and breakers used to protect capacitors. 1) In the event of a capacitor failure it is important to prevent additional energy from reaching the capacitor, which could cause the capacitor can to rupture. 2) It is also important to protect the system by removing the fault current that may occur if a capacitor fails.

Overcurrent protection is discussed in NEC Article 240. Article 240.3 indicates that for certain equipment the reader should consult other articles with information specific to that equipment. For capacitors, the overcurrent protection information in Article 460 applies.

NEC Article 460.8 (B), for low voltage capacitors, states:

> The rating or setting of the overcurrent device shall be as low as practicable.

Note that this statement, in conjunction with the conductor ampacity sizing requirement, means that it is possible to choose an overcurrent device that does not protect the cable against overloads. This can be seen by consulting the recommended wire and fuse/breaker charts for given capacitor sizes published by capacitor manufacturers.

The "as low as practicable" statement means that we want to choose or set our overcurrent protective devices as low as possible. But going too low can cause nuisance trips. Capacitors can draw significant inrush current when energized.

The Bussman "SPD Electrical Protection Handbook" [13] makes some recommendations for capacitor fuses.

> Generally, size dual-element, current-limiting fuses at 150% to 175% of the capacitor rated current and size

non-time-delay, fast-acting, current-limiting fuses at 250% to 300% of the capacitor rated current.

At first glance this looks like a very large difference in fuse size. These sizing recommendations are driven by how quickly the fuses respond to high current faults. The time-current characteristics of these fuses are very different, and the fuses must be selected based on their behavior for high current, short time (inrush) events, not by their nominal (long time, overload) ratings.

Consultants often specify 200 kA interrupting capacity current-limiting fuses in low voltage capacitor banks. Because of this, many standard capacitor designs use such fast-acting fuses. Even though it looks like the fuses are oversized, they are not. The time current characteristics of these fuses require a larger nominal fuse size to avoid nuisance tripping.

D. Unbalance Protection

Large, medium voltage capacitor banks can be made up of many capacitors in series and parallel groups. In some cases, the capacitors are individually fused (whether internal to the capacitor, or externally). If a capacitor fails the fuse will remove that capacitor from the circuit. Even so, this removal of capacitance from the circuit can cause an unbalance in the capacitor bank, which can stress the remaining capacitors.

Unbalance protection, while not required by code, is used to prevent such continuous overvoltage conditions from stressing and potentially failing individual or groups of capacitors when one or two capacitors fail or blow fuses. This is very common on large medium voltage capacitor banks such as utility substation capacitors. Generally, unbalance protection uses two settings, alarm and trip. If the unbalance does not cause enough continuous overvoltage on individual capacitors to exceed their ratings, the system alarms. It trips immediately if the unbalance causes an overvoltage that would stress the capacitors to failure.

E. Capacitor Discharge

Capacitors are energy storage devices. If this energy were allowed to be stored in the capacitor indefinitely it could be a safety hazard. Long after the capacitor bank is disconnected it could retain a dangerous amount of energy.

The NEC specifies that capacitors shall have an automatic means to discharge this trapped charge. Typically this means either internal or external discharge resistors.

NEC Article 460.6 (A), for low voltage capacitors, states:

> The residual voltage of a capacitor shall be reduced to 50 volts, nominal, or less within 1 minute after the capacitor is disconnected from the source of supply.

NEC Article 460.28 (A), for capacitors over 600 V, states:

> A means shall be provided to reduce the residual voltage of a capacitor to 50 volts or less within 5 minutes after the capacitor is disconnected from the source of supply.

If a capacitor bank is not properly discharged, or if it is switched back into the circuit before it has been allowed to discharge, can result in greater than normal capacitor switching transients. This is discussed later in this paper.

V. Capacitor Selection

A. Overview

Selecting the "right amount" of kvar compensation is relatively straightforward. For example, the amount of capacitance required to change the existing power factor from 0.75 lagging to 0.95 lagging is a simple calculation. However, selecting the actual size and type of capacitor is not always straightforward. Several variables, including the fact that you generally have to choose from nominally available sizes, the type and variability of the load, and the physical and electrical location are all significant considerations when selecting the capacitor. Some important considerations for determining the type and size of power factor correction equipment are:

- Utility penalties
- Installed cost and payback of equipment
- Load variability
- kW losses
- Self excitation of motors
- Harmonic resonance
- Voltage regulation
- Load requirements (flicker requirements)

These considerations will potentially lead to significant differences in equipment selection and placement.

B. Equipment Cost

Payback on the investment of installing power factor correction equipment is typically the main criteria for approval. A very rough estimate of installed cost of various power factor correction solutions is shown in Table 4. With larger capacitors there will be some reduction in cost and, similarly, for very small capacitors, the cost may be somewhat more than these values. A rough rule of thumb for fixed capacitors is that the cost of the capacitor itself is approximately 1/3 of the total cost. The remainder of the installed cost includes the protective device (breaker/fuse) and the installation labor and material. For switched capacitors, the cost of the capacitor is typically a larger proportion of the cost.

Table 4

Installed Cost Comparison of Power Factor Correction Equipment

Type of Correction	**Installed Cost, $/kvar**
Fixed (LV – motor applied)	$15
Fixed (LV)	$25
Fixed (MV)	$30
Switched (LV)	$50
Switched (MV)	$50
Static Switched (LV)	$75
Switched Harmonic Filter (LV)	$75
Switched Harmonic Filter (MV)	$60
Active Harmonic Filter (LV)	$150

C. Nominal Size and Configuration

Capacitors are available in a variety of sizes. In the smaller sizes at low voltage they are available in very small increments. In larger sizes they are typically available in 50 or 100 kvar increments.

Low voltage capacitors are typically internally connected in a three-phase delta configuration. Medium voltage capacitor banks can be comprised of single-phase or three-phase capacitors connected in wye or delta configurations.

D. Fixed versus Switched Capacitors

As discussed earlier, the determination of the instantaneous, peak, and average power factor vary greatly. Consequently, the billed power factor or target power factor may be much different than the "typical" power factor during peak or off-peak loading periods of a normal day. Most power systems have some variability in loading throughout the day. Typically, commercial and light industrial loads peak during the day and are substantially lower overnight while minimal infrastructure loads are energized and operating. Heavy industrial and process oriented loads are consistent during "normal" operation but may vary greatly through various stages of the process.

Because of this variability in loading, switched capacitors are often required to minimize power factor penalties, to regulate voltage, and to minimize system loading. Still, it is very difficult to beat the cost and simplicity of applying a fixed capacitor bank. The following paragraphs discuss some of the considerations for switched capacitor banks.

The main advantage of a switched capacitor bank is that it automatically brings on only as much kvar as you need at any given time, provided that it is sized large enough. You do not need to turn it on at the beginning of the shift, nor turn it off at the end of the day. One disadvantage is that if there is a certain critical amount of capacitance that will tune the system to a problem harmonic frequency, an automatic bank will likely find it as it adds and removes capacitance.

Switched capacitor banks have an electronic controller that senses the system power factor (measuring system voltage within the capacitor bank and system current via an external CT or CTs) and regulates the number of steps or stages that are energized. The controller is programmed to raise the system power factor to a "target" power factor.

LV capacitors often have more stages/steps than MV systems. MV switched capacitors require significant additional cost per switched stage because of the required switching devices (contactors) and required physical space required for the switching components.

One method for achieving multiple step variability without having multiple switching devices is to use different size switching steps. For example, if the load varied greatly and 1500 kvar of MV capacitors was required, one could use 1 X 300 and 2 X 600 kvar stages. This would allow steps of 300, 600, 900, 1200, and 1500 kvar with three switching devices instead of five. This is often done in MV systems and is sometimes seen on LV systems. The disadvantage of such an approach is that not all the stages would be receive equal use. With equal size stages a controller can equalize the duty on all the stages.

A high percentage of switched capacitor banks are switched with mechanical contactors. These contactors are relatively inexpensive and are simply used as a switch. The control algorithm switches steps in and out in order to maintain a set power factor. It does not switch in steps as soon as the power factor falls below a certain level nor does it switch out banks as soon as the power factor rises above a certain level. Rather, it waits to see if the condition persists for a (programmable) length of time to avoid excessive hunting, or the constant switching in and out of a step.

The control algorithm also avoids switching in a step within one minute (5 minutes for MV capacitors) after it has been disconnected. This allows trapped charge to dissipate to less than 50 V before reconnecting them. This is done so that capacitors are not switched in when they have a trapped charge that might lead to an excessive switching transient.

E. Static Switched Capacitors

Some LV loads require much faster kvar compensation, often within one 60 Hz electrical cycle (16.7 msec). These switched capacitors are often called static switched capacitors (sometimes adaptive var compensators) and are controlled by power electronic switches (SCR/thyristors). With these devices the controller can precisely control when the capacitors are switched on. By matching the system voltage with the capacitor voltage, even if a trapped charge exists, capacitor switching transients can be largely eliminated.

These static switched capacitors are often required for minimizing voltage flicker and other problems due to high impact loads such as spot welders. That is, they provide additional benefits well beyond simple power factor correction. The disadvantage of these systems is their higher cost.

F. Overvoltage Considerations

When the load varies greatly, fixed capacitors or switched capacitors with steps larger than required for correcting the power factor may lead to overcompensation and excessive leading power factor. The most substantial issues resulting from leading power factor are system overvoltage and generator regulation issues. Simply stated, generators prefer a lagging power factor load. A generator can find it difficult to properly regulate its output voltage when serving a leading load.

If a capacitor is left connected to lightly loaded or unloaded system (resistive and reactive loads disconnected), the system voltage will rise. How much the voltage will rise depends on the impedance of the upstream distribution system and the amount of kvar connected. Figure 1 shows

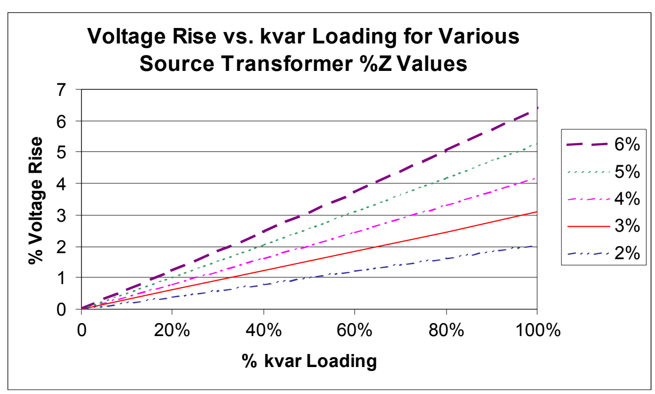

FIGURE 1. VOLTAGE RISE VERSUS KVAR LOADING

the voltage rise based on the transformer impedance (assumed to be the bulk of the upstream system impedance) and the size of the capacitor bank relative to the transformer size.

People applying capacitors are often concerned about this voltage rise. It is important to realize, however, that there is often much greater voltage variation due to improper transformer tap selection and, more importantly, to utility voltage variation. Voltage rise due to the capacitors is just one of the factors to consider. Importantly, when the load is light (overnight or over the weekend) the utility system loading may also be light and therefore the system voltage may be higher than nominal. Therefore, with a large capacitor on a lightly loaded system, the overall system voltage may be much higher than desirable (5-8% higher than nominal, for example). Where harmonic filters are required and used for kvar compensation, similar considerations for balancing the load with the applied kvar are important.

VI. Capacitor Placement

A. Physical Location of Capacitors

An induction motor will roughly draw a fixed kvar across its entire loading range. Unloaded motors have a very low power factor (0.20, for example). As the kW load increases, the power factor increases up to the nameplate value at full load. Prior to the recent influx of harmonic loads, applying a fixed capacitor switched on and off with the motor contactor or breaker was a great way to minimize the kvar required by motors on the system, loaded or unloaded.

It also ensured that overcompensation and the associated issues would not occur since the capacitor was switched on and off with the motor. Distributed capacitors also reduced the overall system losses by reducing the rms current feeding each motor or MCC. Motor and capacitor manufacturers have tables for sizing motor applied capacitors.

The most significant issue with motor applied capacitors is "self-excitation." This occurs when a motor has enough inertia to keep spinning once disconnected from the power system and the capacitor is large enough to supply the reactive power needs of the motor. Self-excitation can cause damaging overvoltages. It can also cause damage to the motor shaft if the motor is reconnected to the system while still rotating due to self-excitation. This issue is well documented in many technical papers. Due to self-excitation concerns, all motor applied capacitors are smaller than the total required kvar of the motor.

A capacitor should not be placed downstream of a motor starter such that it would see sudden voltage changes. The capacitor may be placed downstream of the main contacts in a starter where it will see a steady voltage, but not further downstream (output of the entire starter) where it would see the varying voltage sent to the motor.

Capacitors should not be placed downstream of softstarts (capacitor will see a very distorted waveform with sudden voltage changes, and will fail) unless it is connected via a contactor that only brings the capacitor on-line after the softstart has been bypassed. Many softstarts have auxiliary contacts to convey this information.

Important considerations regarding motor protection (not in the scope of this paper) should be considered before applying capacitors to motor terminals because the total motor current is reduced when a capacitor is applied at the motor terminals.

Today, with harmonic currents generated by many of the loads on a typical power system, having many capacitors spread around the system could result in many harmonic resonances in the system. Harmonic current could see the inductance of a length of cable along with the capacitance on a given motor at the end of that cable as a tuned harmonic filter. That "filter" will attract harmonics from throughout the system and overload the capacitor. The result is a situation where one or a few capacitors on certain motors keep failing while others are completely unaffected. The safer design choice is to apply capacitors at the main distribution or MCCs if harmonics are a concern.

In addition to harmonic concerns, the reason for applying kvar compensation might dictate the proper location for capacitors, on motors or at a more central location. Generally, if a utility power factor penalty is the main concern, then applying capacitors at the main switchgear is appropriate (compensation only needs to be downstream of the utility metering). If kVA reduction or loss (kW) savings are a concern, then applying the capacitor compensation at or near the loads is the most appropriate solution.

Loss reduction on the order of 1-2% of the overall kW consumption is possible with distributed capacitors. Note that many unscrupulous and/or unknowing salespeople will claim much higher kW savings but greater than 2% is extremely unusual. Because of this, kW savings alone are typically not enough to justify the cost of applying capacitors. The payback based on loss savings is generally 10 years or more.

B. Electrical Location of Capacitors

Another consideration is whether to apply the capacitors at low voltage or at medium voltage, if that option is available. There are a number of reasons why you would choose one or the other.

If there are many low voltage unit substations, it may be more cost effective to install one medium voltage bank than multiple low voltage banks.

Sometimes the physical space available, whether there is more space at the low voltage locations or in the medium voltage substation, will dictate the choice. If a large amount of capacitance is needed it may simply take too much space to apply multiple low voltage banks that provide enough kvar.

Some companies choose to apply low voltage capacitor banks solely on the basis that their electricians are trained to work on low voltage equipment but will not touch medium voltage equipment, even if de-energized.

In some cases, if there are significant amounts of harmonics on the low voltage services, it may be possible to avoid a harmonic problem by applying a medium voltage bank, rather than low voltage banks. The impedance of the transformer might serve to isolate the harmonics to some degree and it may be possible to avoid a local parallel resonance problem at the low voltage level. This is a double-edged sword, however, because a medium voltage bank will also be more closely coupled to the utility system. This is another way of saying that the harmonics from your neighbors can much more easily find their way into your medium voltage capacitor bank. It is beneficial to carefully study a medium voltage capacitor bank installation from an overall system point of view to avoid possible utility system interaction issues.

C. CT Location for Automatic Banks

In addition to the placement of the actual capacitor(s), the selection and placement of the current transformers (CT) used in automatic capacitor banks is equally important. The CT should be placed where it will measure the full load needing power factor correction, including the capacitor itself (so the capacitor bank can see its impact on the system).

In most automatic capacitor banks the controller makes the assumption that the load is balanced across all three phases. We are concerned about the overall three-phase power factor, after all. And the capacitors and contactors used are both three-phase devices. It is not possible to separately compensate power factor on different phases.

Therefore, most automatic capacitor banks require only one CT and switch all steps on as a three phase group. Some switched capacitors may require 2 CTs (deriving the third phase current by the addition of the other two phases) or 3 CTs. Note that the location/placement of the CT(s) and its orientation (polarity) are critical to ensure proper operation of the automatic bank.

Field errors when placing capacitor CTs include putting the CT on the breaker serving the capacitor bank, itself. This does nothing to measure the overall system power factor. Sometimes a CT is placed on the middle or the end of a busbar in low voltage switchgear, where it does not measure the full load.

It is also very common that the CT gets placed on the wrong phase or has the wrong orientation (based on what the controller expects). This will result in the controller calculating the system power factor incorrectly and, most likely, not providing power factor correction. The controller may see a leading power factor already, indicating no need to add further capacitance to the system. Or it will get improper feedback when it does switch on a capacitor step—power factor gets worse when a step is added so the controller thinks there is a problem and does not continue to add capacitance.

One simple sanity check during installation is verifying that the controller reads a realistic power factor (not just .8, for example, but .8 *lagging*, not leading—some people miss the second part). This can often be checked against system metering. A second sanity check is watching to see that the power factor improves (gets closer to unity from a lagging power factor) when a step is energized, manually if necessary.

If a CT is installed incorrectly, it is difficult to change after the fact. An outage may have been required to install the CT in the first place, and it may be impractical to take a second outage. This is not a problem because most capacitor banks do not require a second outage because they allow the user to change settings or wiring to compensate for the improper CT placement.

Double-ended substations require careful consideration. The capacitor bank may be placed on either of the secondary buses if the primary buses are tied together (for utility penalty considerations) but the CTs for automatic banks must be in a shared (additive) arrangement to ensure that either or both transformer loads are considered and compensated. Capacitors may be placed on both halves of the double-ended substation if each capacitor bank has summed CTs on its main and on the tie.

It is possible to compensate multiple low voltage services with one capacitor bank, on one of the low voltage busses. This is done by using a summing CT to aggregate the CT currents measuring each low voltage bus. It is important that each low voltage bus be served by the same type of transformer connection (for proper phasing) and the CTs at each bus are connected to the same phase. It is also important that the low voltage bus with the capacitor bank be able to handle leading power factor, and the possible resulting overvoltage, when the capacitor bank is doing significant compensation for the other busses. This approach makes sense if there is one bus with a large service that requires most of the power factor correction.

VII. Harmonics (To Filter or Not To Filter)

A. Overview

It is not possible to talk about capacitor application issues without discussing harmonics. The intention of this paper is not to analyze harmonic resonance but to discuss the issues related to resonance. Unfortunately, resonance is a self-correcting problem: Fuses will blow, breakers will trip, or capacitors will fail, thus changing the resonant points and de-tuning the circuit. Failing equipment is not the most cost effective way to de-tune a circuit, however. Avoiding resonance is challenging, but possible.

IEEE Std 519-1992 [5] discusses the possible effects of harmonics on capacitors. Portions of Section 6.5 of this document are presented below:

> A major concern arising from the use of capacitors in a power system is the possibility of system resonance. This effect imposes voltages and currents that are considerably higher than would be the case without resonance.
>
> The reactance of a capacitor bank decreases with frequency, and the bank, therefore, acts as a sink for higher harmonic currents. This effect increases the heating and dielectric stresses.
>
> The result of the increased heating and voltage stress brought about by harmonics is a shortened capacitor life.

B. Series Resonance

Series resonance occurs when a non-linear load "sees" an inductance (in the form of a transformer, cable, or reactor) in series with a power factor correction capacitor. At some frequency the series combination of the inductance and capacitance will be equal and will sum to nearly zero (ignoring resistance). This is a very attractive path for harmonic current at that frequency. Figures 2 and 3 show series resonance, from the point of view of the load.

Harmonic filters are purposely "series resonant" at a fixed frequency to attract harmonic currents and consequently reduce harmonic voltage distortion. Uncontrolled series resonance generally results in nuisance fuse operation or tripping of circuit breakers, as well as possible capacitor failures.

C. Parallel Resonance

Adding capacitors will cause the power system to be tuned to a certain harmonic. This is known as parallel resonance between the capacitors and the source (including the

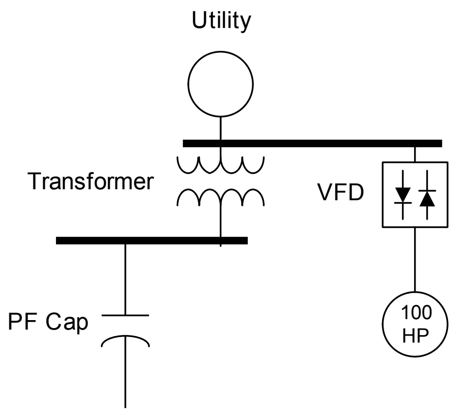

FIGURE 2. SYSTEM SHOWING SERIES RESONANCE

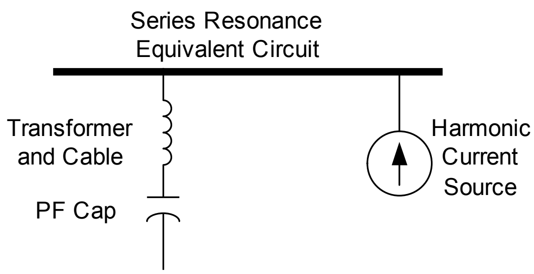

FIGURE 3. SERIES RESONANCE, EQUIVALENT CIRCUIT, RESULTS IN HIGH HARMONIC CURRENT

transformer) inductance (see Figures 4 and 5). This frequency is the crossover point at which the inductive and capacitive reactances are equal.

A parallel resonance presents a high impedance to injected harmonics at or near the resonant frequency, thus amplifying harmonics at these frequencies. It causes problems only if a source of harmonics exists at or near that frequency. This is more likely when the capacitor bank is a switched bank with multiple steps since there are several possible resonant frequencies.

It is unlikely that the injected harmonics will be at precisely the parallel resonant frequency, but near-resonance can be very damaging as well. If, for example, the parallel resonant point is at the 5.3rd harmonic and a source of 5th harmonic current exists on the system, problems are likely. In short, parallel resonance can result if both of the following are true:

- Harmonic-producing loads (such as AC/DC drives, induction heaters, arcing devices, switch mode power supplies, and rectifiers) are operating on the system.
- Parallel resonance exists at a frequency equal or near to the harmonic frequencies produced by the above loads.

The resonant frequency of a system, at a transformer secondary, can be estimated with the following formulas. *h* is the tuned harmonic of the system, X_C is the capacitive impedance of all capacitors connected to the secondary bus of the transformer, and X_L is the inductive impedance of the transformer (plus primary source inductive impedance, if known). The second formula is a simplified version of the first formula, using only the transformer impedance as X_L (usually a reasonable assumption).

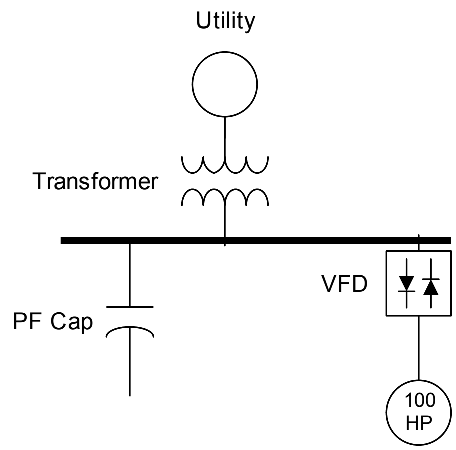

FIGURE 4. SYSTEM SHOWING PARALLEL RESONANCE

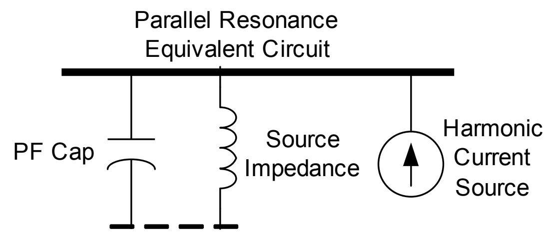

FIGURE 5. PARALLEL RESONANCE, EQUIVALENT CIRCUIT, RESULTS IN HIGH HARMONIC CURRENT

$$h = \sqrt{\frac{X_C}{X_L}} \quad \text{OR} \quad h = \sqrt{\frac{kVA_{transformer}}{Z_{transformer} \times k\,\text{var}}}$$

Example: 1500 kVA transformer, 5% impedance, 600 kvar capacitor:

$$h = \sqrt{\frac{1500}{.05 \times 600}} = 7.1^{st}\ harmonic$$

Therefore, any source of 7th harmonic current on the system will be amplified by the parallel resonant condition. As a rule of thumb, on 480 V, 600 V, and medium voltage (MV) systems, avoid parallel resonance below the 7.8th harmonic (to stay away from the 5th and 7th) and between the 10.3rd through the 13.6th (to avoid the 11th and 13th) harmonics. Because this is an estimated calculation, a change in source impedance or capacitor size will change the parallel resonant point and could be problematic. Other parallel resonant conditions may occur but are less common.

D. Harmonic Filters

A capacitor bank can be configured as a harmonic filter by putting some inductance in series with the capacitance. See the series resonance discussion earlier in this paper. It will still supply reactive power (counter intuitively, more kvar than with the capacitance alone) but will also filter harmonics from the power system. This is known as a passive harmonic filter.

When is a filter needed? One rule of thumb suggests that a potential problem may exist if both the power factor correction (kvar) is greater than 25% of the transformer kVA and the harmonic-producing load (e.g. drive load) is greater than 40% of the transformer kVA. Values below 15% and 25%, respectively, would not be expected to cause a problem.

In the authors' opinion, it is better to do some resonance calculations and get a solid grasp of the situation. If the resonance point falls on a critical harmonic you can run into problems below the "rule of thumb" values mentioned above. If you find that you have both a "significant" amount of harmonic load and your system resonance point is near a characteristic harmonic of your harmonic source(s) (e.g. 5th, 7th, 11th, etc.), then you most likely need a harmonic filter. If either or both are in a gray area then you cannot say for sure without a power system study, but this is not always possible given budget constraints.

Applying a harmonic filter in lieu of a standard capacitor bank avoids the parallel resonance problem by forcing the parallel resonant point to be below the series resonant "tuning" point of the filter. For example, a nominal 5th harmonic filter, commonly tuned to the 4.7th harmonic, is often parallel resonant near the 3.8th harmonic (well below any harmonics of concern, except in very rare instances).

The manufacturer explicitly chooses the series tuning point of the filter and this will not change, but the resulting parallel resonance frequency is determined by the interaction of the filter and the source impedance. The same filter will be a 4.7th harmonic filter regardless of the system in which it is applied, but the resulting parallel resonant frequency may be the 3.8th in one system and the 4.1st in another, for example.

There are several reasons why a 4.7th harmonic tuning point is chosen for low voltage filters and relatively small medium voltage filters. A passive filter is tuned below the nominal frequency to be filtered (e.g. 5th). If a filter is tuned very close to the 5th harmonic it might attract excessive harmonic current (in excess of component ratings). Component tolerances also require that we design a safe distance from tuning precisely to the 5.0th harmonic. As filters age the tuning tends to drift closer to the 5th harmonic, so it is good to start a safe distance from 5.0th tuning.

Large medium voltage filters can be tuned much more closely to the 5th harmonic (4.9th, for example). This is because there are many more capacitors in each group, and the loss of any individual capacitor will not shift the tuning point very much. Such filters are often designed after a more rigorous study, which allows the designer to better know the harmonics expected to flow in the filter and take that into account, despite tuning more closely to the 5th.

If power factor correction is the ultimate goal (as opposed to actually filtering harmonic currents), "de-tuned" filters, 4.1st or 4.2nd for example, may be applied. This reduces the filtering effect of the filter, but results in more of a "plug and play" solution because you do not have to worry about overloading the filter. A small but significant amount of 5th harmonic current will still be filtered, though, just as a 4.7th filter will also provide some filtering at higher frequencies such as the 7th, 11th, 13th, etc.

Other non-typical tuning points (4.3rd in one case) are possible but typically are used on a case-by-case basis, more typically at medium voltage (again, after detailed study). This is sometimes done to precisely place the parallel resonant point (at the 3.5th harmonic, with the 4.3rd tuning mentioned above).

There are many other considerations when applying harmonic filters:

- Multiple capacitors at different locations (e.g. capacitors on multiple motors) can cause multiple resonance points. This is a significant reason why distributed capacitors are not recommended today where many harmonic sources are prevalent.
- Often, users assume that harmonic filters attract all harmonic currents. This is not true. Most filters are detuned enough (4.7th applied as a 5th filter) that they only absorb roughly half (ballpark: 30-70%) of the harmonic current on a typical system.
- If a fixed filter is applied on an individual load, a reactor must be placed upstream of the filter and load, otherwise the filter may become overloaded. The user's intention may be for the filter to filter only harmonics from that load, but it may attract harmonics from elsewhere in the system.
- Harmonic-producing loads with a high power factor (e.g. drives) can be a tricky proposition for passive filters. It is natural to want to add a filter for a drive. But this could lead to a situation where a very small filter is used or very few steps of an automatic filter bank are on-line (because very little kvar is needed for power factor correction). This small amount of capacitive filtering would then have to sink a very large amount of harmonic current. Note that the 60 Hz current in such a filter is determined by the equipment (nameplate kvar) but the harmonic current is determined by the harmonic loads in the system and the impedance of the filter. In short, it is possible to overload the filter. If such loads are just part of the overall load then this is not generally a problem.
- With automatic filter banks, it is desirable to switch on the filter steps as quickly as possible. If many harmonic-producing loads come on-line at once, and if there are long delays when switching the filter bank, one small filter step may be left to sink a lot of harmonic current until the next steps switch on. This may also occur if a filter bank is configured with a few fixed steps, therefore fixed filter steps should be avoided.
- A harmonic filter should be specified first by the amount of 60 Hz power factor correction required and then specify the tuning point (typically 4.7th for tuned or 4.2nd for de-tuned). Then, based on measurements or estimates, determine if the filter will be overloaded by harmonic currents.
- If multiple filters are applied, switching order (first on/off) is very important. Lowest order on first and off last. For example, 5th on, 7th on, then 7th off, 5th off. This is due to parallel resonance concerns. A 7th harmonic filter may produce a parallel resonance near the 5th harmonic. If the 7th harmonic filter is left on-line alone, it might amplify harmonics near the 5th.
- Capacitors used in a harmonic filter must have a higher than nominal voltage rating. Generally, 550 V or 600 V capacitors are used in 480 V filters. There is a steady-state voltage rise due to the inductance in series with the capacitor (even if no harmonics are present). There will also be higher peak voltages on the capacitors due to harmonics flowing in the filter. Therefore you cannot convert a standard rated capacitor into a filter or it could potentially fail from overvoltage. It is possible to buy a straight capacitor bank with higher voltage capacitors if you might want to convert to a filter later, however.

- If an automatically switched capacitor bank is to be configured as a filter, each step in the bank must be configured as a filter by adding a reactor in series with each capacitor step.
- Medium voltage and low voltage filters are specified differently. At low voltage it is common to specify the filters based on nameplate capacitor kvar ratings at applied voltage (e.g. kvar at 480 V, even if 600 V capacitors used), ignoring the increased kvar effect of the filter reactors. At medium voltage it is more common to specify an effective filter kvar at the nominal voltage.

E. Application Advice

When harmonics and capacitors are discussed, even in an overview paper such as this, people may feel overloaded and not know where to begin. Follow these general steps:

1. Perform a resonance calculation. This is necessary for each step of an automatically switched bank. That is, do the resonance calculation for each possible amount of capacitance. As mentioned in Section I, this can be easily done with a spreadsheet.
2. If the harmonic resonance is not close to characteristic harmonics of typical harmonic-producing loads (5th, 7th, 11th, 13th, etc.), apply straight (non-filtered) capacitors.
3. If the harmonic resonance is close to characteristic harmonics consider filters (4.7th tuning), de-tuned bank (4.2nd tuning), or further study.
4. If extremely heavy drive or rectifier loads are present, passive filters may become overloaded. Consult the manufacturer or study further.

VIII. CAPACITOR SWITCHING TRANSIENTS

A. Overview

A capacitor switching transient is a normal system event that can occur whenever a capacitor is energized. Typically, de-energizing a capacitor does not cause a system transient. On energization, the transient occurs because of the difference between the system voltage and the voltage on the capacitor. A basic characteristic of capacitors is that the voltage across them cannot change instantaneously. If a capacitor is at zero voltage and system voltage is applied to it, the system voltage will be pulled down to nearly zero momentarily.

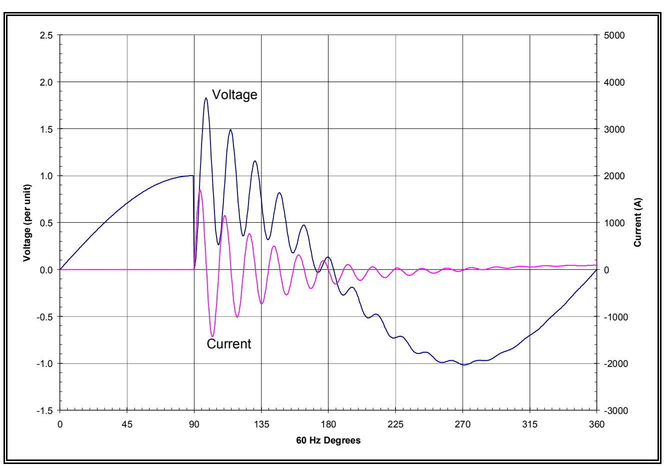

FIGURE 6. CAPACITOR ENERGIZATION TRANSIENT

There will then be a capacitor inrush current as the capacitor charges. The voltage on the capacitor will then recover and overshoot the system voltage by roughly the same amount that it dropped, and then oscillate around the 60 Hz system voltage. It is possible for this overvoltage to reach nearly 2.0 per unit (twice the peak system voltage) if the capacitor is initially uncharged and the switching occurs at the peak voltage. System impedance usually keeps this overvoltage from reaching the theoretical peak.

The capacitor voltage will continue to oscillate around the 60 Hz fundamental waveform, with the oscillation gradually getting damped out, usually within a cycle depending on the system resistance. The magnitude of the transient and its characteristic oscillation frequency will depend on the characteristics of the electric power system in question.

The magnitude of the transient will vary based on two variables at the time of the switching. These variables are the initial voltage on the capacitor (trapped charge, usually close to zero if the capacitor has been allowed to discharge) and the instantaneous system voltage at the time of the switching. The greater the difference between these two voltages, the greater the magnitude of the transient. The worst case transient will occur when the system voltage is at peak voltage and there is a trapped charge on the capacitor of peak system voltage at the opposite polarity.

Recall that the NEC requires resistors to discharge capacitors rated 600 V and lower to 50 V or less within one minute (and less than 50 V in five minutes for MV capacitors). The control algorithm in an automatic capacitor bank avoids switching in a step within one minute after it has been disconnected, so in normal operation there should be very little trapped charge on the capacitors when switching. But in manual mode or with fixed capacitors switched with a breaker or disconnect, this situation can and does happen.

Trapped charge may occur if:

1. The discharge resistors failed or became disconnected.
2. The capacitors were switched manually before they were allowed to discharge.
3. The capacitor control unit switched the contactors too quickly (improper settings), before the capacitors had adequate time to discharge their trapped charge.
4. Contactor bounce/chatter or circuit breakers restrike during opening. Both of these events may lead to multiple trapped charge scenarios causing significant transients and voltage escalation due to trapped charge on a capacitor. These types of events typically lead to catastrophic failure of equipment.

With regard to this last point, it is important that contactors or breakers be capable of interrupting capacitive current, especially at medium voltage. The interrupting duty depends on the configuration of the capacitor bank and the system, and can be as high as 3 per unit (of the normal line-to-neutral voltage), or even higher (3.46 pu) if there is a failed capacitor [14].

B. Back-to-Back Capacitor Switching

Another type of capacitor switching transient is called back-to-back switching. This situation occurs when a second capacitor is switched on in close (electrical) proximity to a previously energized capacitor. In this case a higher

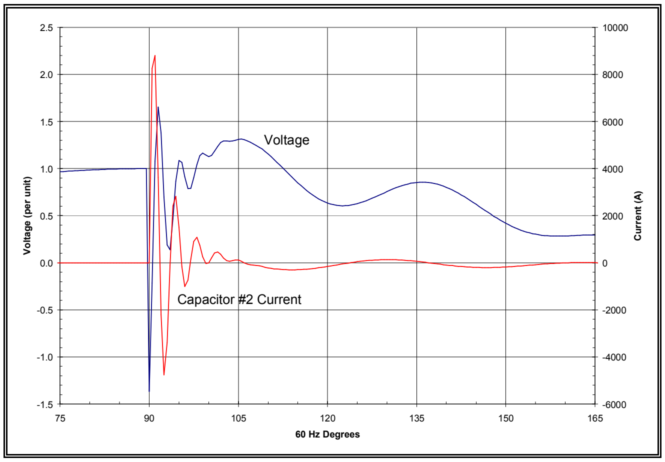

FIGURE 7. BACK-TO-BACK CAPACITOR SWITCHING TRANSIENT

frequency transient initially occurs as the previously energized capacitor shares its charge with the newly energized capacitor.

The previously energized capacitor pushes current to the other capacitor as a source in parallel with the utility. When they are in close proximity to each other, there is often very little impedance between capacitors. This allows a very high outrush current from the previously charged capacitor and inrush to the charging capacitor. After this initial inrush, there is another transient as the pair of capacitors cause the voltage to oscillate around the 60 Hz fundamental voltage, as described above, as if they were a single capacitor bank.

Figure 7 shows the energization of a 50 kvar, 480 V capacitor step with trapped charge and with 150 kvar of other capacitor steps in service. The energization occurred at peak system voltage. The time scale for Figure 7 is greatly zoomed in from that in Figure 6, to better show the higher frequency initial transient.

C. Minimizing Capacitor Transients

There are two basic ways to minimize capacitor switching transients. One way is to switch the capacitor at a point in time when the system voltage matches the voltage on the capacitor, even if there is a trapped charge. This is only possible with a switching device that can be precisely controlled, and is done with static-switched capacitors, as described earlier in this paper.

Another way is to insert some impedance, resistance or inductance, in the circuit to minimize the transient (limit the capacitor inrush current, thus minimizing the resulting voltage oscillation). Harmonic filters do this naturally because there is an inductor in series with the capacitor. Some people choose harmonic filters largely to reduce transients, in addition to the harmonic benefit. Some purists feel that iron-core reactors do not minimize the transients as much as one might expect, because the core can saturate, but in the authors' experience iron-core reactors do a good job reducing the transients. Note that large, medium voltage filter banks often use air-core reactors, which do not saturate.

Sometimes a small inductor is added in series with a switched capacitor (often done at MV). In some cases at low voltage this is done by coiling some wire in the circuit, although a couple of coils provide only a minimal amount of inductance.

Pre-insertion resistance or inductance is sometimes employed in the contactors or switches used to minimize capacitor switching transients. This is an excellent solution for unfiltered capacitor banks. This has been done at medium voltage in certain applications when necessary, and is now available in low voltage switched capacitor banks.

In such a low voltage contactor there are actually two sets of contacts. The first set to close has some resistance or inductance in series with the contacts, thus limiting the transient. The second set does not, thus shorting out the first set and carrying all the current once it closes. The first set is smaller because it only has to carry current momentarily.

D. Utility Capacitor Switching Magnification

Utility companies switch large substation capacitor banks, often daily, to provide reactive power and voltage support during peak load conditions. Often, these banks are switched on in the early morning as loads increase and they are turned off later in the day when loads decrease. During the energization, a switching transient occurs on the power system at a natural frequency typically in the range of 300-1200 Hz. During the de-energization, no significant transients occur on the power system.

This switching transient during energization cannot exceed twice the peak sinewave voltage. Typically, the resulting overvoltage is approximately 1.2-1.6 times the normal peak voltage. However, if a customer has a capacitor applied on their power system on the secondary side of a step-down transformer, as shown in Figure 8, and if the inductive reactance of the transformer and cables between the two capacitors matches the capacitive reactance of the customer's capacitor at the natural switching frequency of the utility capacitor, the customer capacitor (already pre-charged) tries to maintain its terminal voltage and immediately dumps significant current into the utility capacitor bank. The impedance of this circuit looks like a short circuit at the switching frequency of the utility capacitor, thus allowing significant back-to-back transient current. By pushing this large amount of current through the step-down transformer, the customer voltage oscillates significantly at the switching frequency as shown in Figure 9. Notice that in Figure 10, with the customer capacitor removed, the oscillation from the utility capacitor switching event is greatly reduced.

The magnitude of the transients and the oscillations are significant enough to cause equipment failure. In some cases, equipment may misoperate or shutdown when multiple zero crossings occur as a result of these exaggerated voltage

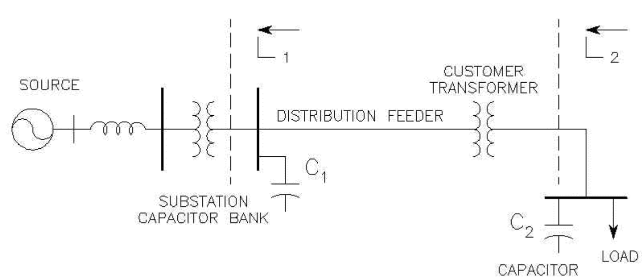

FIGURE 8. VOLTAGE MAGNIFICATION CIRCUIT

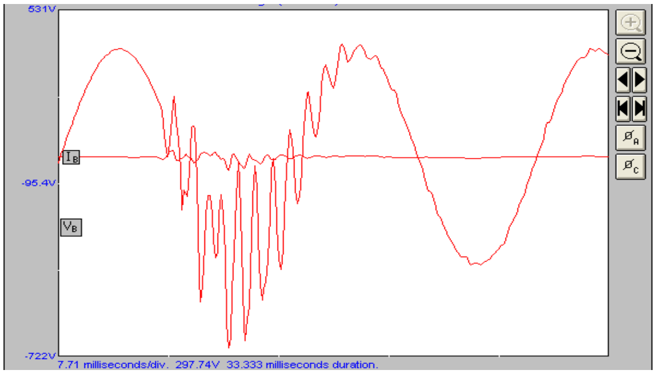

FIGURE 9. UTILITY CAPACITOR ENERGIZED WITH LV CAPACITOR ENERGIZED: VOLTAGE MAGNIFICATION AT 480 V BUS

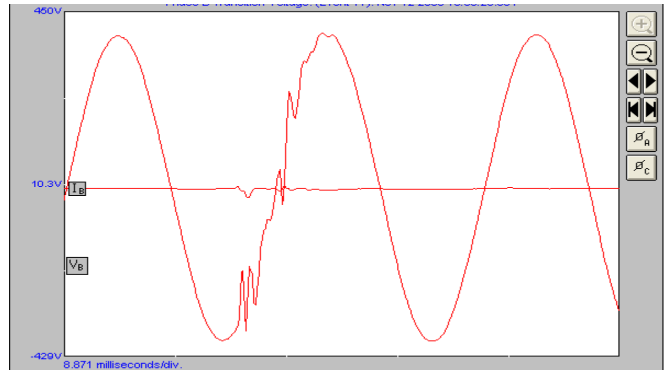

FIGURE 10. UTILITY CAPACITOR ENERGIZED WITHOUT LV CAPACITOR ENERGIZED: NO VOLTAGE MAGNIFICATION

oscillations, as shown in Figure 9.

This is a relatively rare situation but it can and does happen frequently enough to watch for this issue. This problem can be rectified by changing the natural frequency of the customer system by adding inductance in the form of reactors or an isolation transformer, or changing the size of the capacitor bank. Alternatively, another method of power factor correction can be used in lieu of standard capacitors on the customer system, such as harmonic filters or active filters.

IX. CAPACITORS AND FAULT CURRENT

The question is often asked, “Should capacitors be included in fault studies?” The simple answer is, no. The reasoning is relatively simple. An energized capacitor will very quickly discharge into other loads (or the fault) within ¼ of a 60 Hz electrical cycle at a frequency much higher than the fundamental fault current. This is significantly different than motors operating on the system that will “generate” back into the faulted system and contribute to the overall fault current. Therefore, since capacitors do not offer a significant source power during a fault, they can be ignored. This is the standard used in commercially available power system modeling programs.

X. CONCLUSION AND SUMMARY

With so many potential problems in applying power factor correction capacitors on a power system, why would an engineer consider applying them? Capacitors offer real savings on the utility bill, reduce system losses, and help to stabilize voltage, all while increasing system capacity.

Understanding the potential for problems and applying engineering judgment and economic analysis will lead to safe and reliable operation of power factor correction solutions. This paper presents some of the practical considerations to evaluate before, during, and after capacitors are applied on a power system.

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XII. Authors' Biographies

Thomas M. Blooming, P.E. (S '89, M '94, SM '05) is an Application Engineer with Eaton Electrical, supporting Eaton's power quality products. He focuses on uninterruptible power supply (UPS) application issues. Tom formerly was a Senior Product Engineer in the Power Factor Correction Group of Eaton Electrical (Power Quality Division). He handled application issues related to power factor correction capacitor banks, harmonic filters, static-switched capacitor banks, and active harmonic filters, as well as many power quality-related questions. Prior to that Tom worked in the Cutler-Hammer Engineering Services & Systems (CHESS) group and provided clients with electric power engineering expertise, focusing in the areas of power quality and reliability. Tom has performed numerous power systems measurements and studies. He has published technical papers and taught engineering workshops and training seminars on power quality issues. Tom received a B.S. in Electrical Engineering from Marquette University, an M.Eng. in Electric Power Engineering from Rensselaer Polytechnic Institute, and an M.B.A. from Keller Graduate School of Management.

Daniel J. Carnovale, P.E. (S '86, M '90, SM '02) is the Power Quality Solutions Manager at Eaton Electrical. Dan is responsible for developing strategies and tools for reliability and productivity solutions across the Electrical Group's eight equipment divisions and Engineering Services group. Dan has developed Eaton's Power Quality Experience Center and Lab where PQ problems are created and mitigated for demonstration and testing purposes. He has developed and teaches CEU-certified technical seminars on Power Systems and Power System Analysis. Dan has conducted several hundred Power Quality site investigations for commercial, industrial and utility power systems: evaluating PQ issues and applying solutions. Dan worked for Westinghouse Engineering Services and ABB Power T&D. He received his B.S. Degree in Electrical Engineering from Gannon University and his M.S. Degree in Power Systems from Rensselaer Polytechnic University. He is a registered Professional Engineer in the states of Pennsylvania, California and Alaska and a Certified Energy Manager (CEM).