SMART GRID LTC TRANSFORMER CONTROL AND DUTIES

E. Tom Jauch
Life Senior Member, IEEE
Application Consultant–Beckwith Electric Company, Inc.
jauch@ieee.org

I. INTRODUCTION

Analysis of premature failure of load tap changer (LTC) transformers on utility systems often identifies the tap changers as a major contributing factor. LTC factors responsible for transformer failures include: oil quality (particulate contamination), LTC contact temperature rise, contact coking, carbon film build-up, short circuit mechanical forces and contact wear and arcing. Some of these are a result of the contact film or tarnish that builds up on all contacts operating in oil. These factors create increasing contact resistance—thereby increasing voltage drop, localized heating, contact pitting, oil contamination and general deterioration.

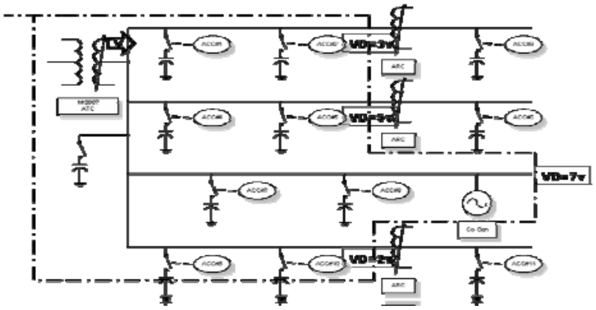
Any cumulative damage, which will affect the transformer life, can be a function of the number of operations as well as the loading conditions when those tapchanges occur. Numerous operations in a few tap positions may accelerate the deterioration of other tap contacts due to the dispersion of damaging products in the oil. Unacceptably frequent, unnecessary or poorly-timed tapping operations of LTC transformers can substantially contribute to the acceleration of these damaging conditions [1].

The objectives of a coordinated Smart Grid (SG) Integrated Volt Var Management (IVVM) system includes reducing system-wide losses, minimizing distribution system and customer voltage variation, reducing maintenance and operating costs, reducing/deferring capital spending and increasing the power delivery capacity of existing equipment. In the case of CVC (conservation voltage control) applications, an added objective is maintaining customer voltage levels to minimize power consumption on the system. In completing the majority of these objectives, the effect on LTCs is an increase in LTC operation numbers and therefore, LTC duties.

As the implementation of the SG progresses, it is expected that the LTC equipment will have changing/increasing IVVM duties. Figure 1 outlines a typical isolated radial distribution system. The simple system shown consists of one source LTC transformer from the transmission or sub-transmission system, one bus capacitor bank (single or staged), four load feeders—each with pole-top switched capacitor banks with capacitor controls, three with line regulators with regulator controls and one with distributed generation (DG). The operation of the distribution capacitor banks (system var control) has a major and direct effect on the operating duties of both the LTC transformers and the line regulators on the system.

The system illustrated in Figure 1 shows an arrow located at the substation power transformer. This depicts the location of the LTC control which has responsibility to regulate the voltage in its “Area of Responsibility” (AOR). This control’s AOR is designed to include all consumers up to the point where another device assumes that responsibility. In Figure 1, the AOR is shown as the framed area of the circuit (up to the next line regulator on each feeder). Also illustrated in Figure 1, is the full load voltage drop from the LTC transformer to the end of its AOR on each feeder. These are shown as 3V, 5V, 7V and 2V from the top feeder down. The magnitude of the largest full-load AOR voltage drop has a direct effect on the LTC number of operations.

This paper discusses the expected SG IVVM functions, and their effects, on the operating duties of LTC transformers and line/substation regulators. In general, these changes will be initiated by a) CVC implementation, b) reverse power operation requirements, c) the integration of DG on power systems and d) system var control.



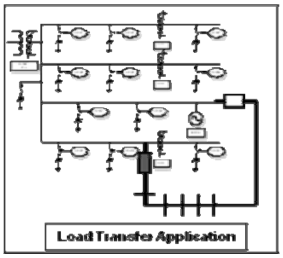
Sample Radial Distribution System
FIGURE 1

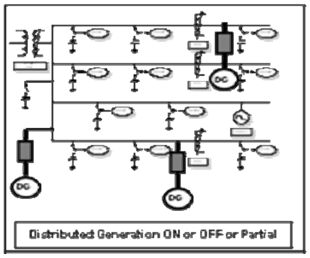
II. SG SYSTEM CONFIGURATIONS POSSIBILITIES

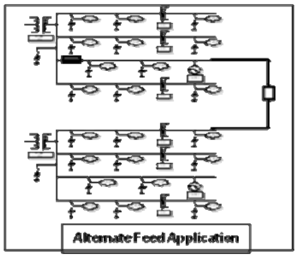
Figure 2 illustrates a “Possible SG Distribution System” configuration developed with some of the separate operating conditions that it could be required to provide. The operation of strategically-placed feeder switches as shown could create multiple system configurations ranging from radial operation to full network operation. The myriad of operating conditions of these multiple possible configurations will require significant duty changes on distribution equipment to maximize the effectiveness of the SG system.

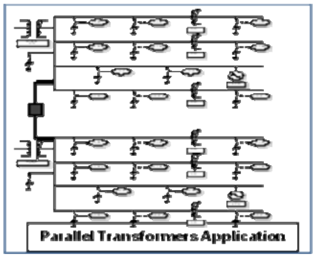
The circuit in Figure 2 also allows for several common or possible future beneficial SG applications:

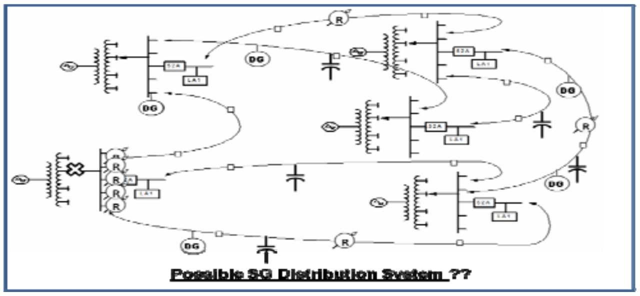
1) “Load Transfer Application” allows a specific load, DG or circuit section that could be fed from either of two substation circuits.
2) “Distributed Generation ON/OFF/Partial” allows for multiple applications of any type of DG on the distribution system.
3) “Alternate Feed Application” allows for a common application of providing an alternate (automatic) source to back up critical distribution loads.
4) “Parallel Distribution Transformer Applications” allows for the paralleled transformer conditions that can be activated in one substation or by circuit connections between substations.
5) “Possible SG Distribution System” illustrates the combination of these several interconnections to accomplish greater SG IVVM system benefits. Circuit switchers on the distribution feeders are available for changing the configuration of individual feeders or on all feeders.











Components of an SG System Configuration
FIGURE 2

III. THE EFFECT OF SG CVC

A. CVC Purpose and Effectiveness

A Pacific Northwest analytical team recently completed a three-year research and demonstration study on CVC [2]. The study detailed results showing conclusively that operating a utility distribution system in the lower half of the acceptable voltage range (114-120 volts) can save energy, reduce demand, and reduce reactive power requirements.

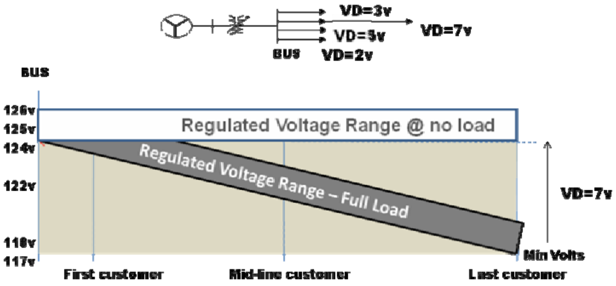
Specifically, the energy savings results were within expected values of 1-3% total energy reduction, 2-4% reduction in kW demand, and 4-10% reduction in kvar demand.

An outstanding feature of CVC is the large reduction in var requirements on the distribution system (4% var reduction for each 1% voltage reduction). The resultant decrease in var flows on the distribution system are reflected in less system voltage drop, more level feeder voltage profiles, lower system losses and better voltage (and load) control. The increased sensitivity of voltage control will increase the LTC operations, whereas the reduction in var flows will tend to reduce them.

The CVC features of an SG IVVM system can be implemented directly on the power systems, with no detrimental operating effects, without individual consumer actions.

B. CVC Operation

The lower edge of the “Regulated Voltage Range-Full Load” block in Figure 3 illustrates an example possible full load feeder voltage profile. As shown, the voltage drop along the feeder is the 7V described. (Bus-124V to Last Customer- 117V)



Feeder Voltage Profile (Common Setting)
FIGURE 3

1) LTC Transformer Operations with No CVC results

The “Regulated Voltage Range” blocks in Figure 3 illustrate the effects of a common (no CVC) setting for the bus LTC transformer control. The control setting shown is: a bandcenter of 125V and a bandwidth of 2V. When the bus voltage remains out of this voltage band for a minimum time, the control will call for a tapchange to return the voltage into band. This setting allows a customer maximum of 126V (at the substation) and a minimum of 117V (at the last customer location). Note that the 3V margin from the allowable customer minimum of 114V is to allow for local voltage drop.

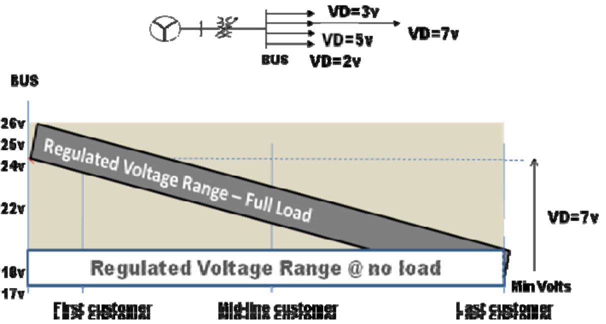
Notice that as the circuit load varies from no-load to full-load, the last customer voltages could vary from 117V to 126V. However, the bus voltage would remain in the designated bandwidth. <u>No</u> adjustment of the bus voltage is necessary over the entire load level range (i.e., no tap changes on the bus LTC transformer or regulator).

2) LTC Transformer Operations with CVC

In contrast to the no CVC application, the CVC control of the lowest customer voltage results in much greater LTC transformer duties. This application is illustrated in Figure 4.

Whereas the full-load voltage profile is the same as the no CVC case, the voltage profile of the no load (or reduced load) is much lower. The availability of the SG system data and communications capabilities allow for continuous setting changes of the LTC control to regulate the lowest voltage customer rather than the local bus.

Notice that as the circuit load varies from no-load to full load, the customer voltages could still vary from 117V to 126V. But it is the first customer rather than the last customer that sees the extended range. With CVC, all customers on the circuit now experience the minimum voltage levels possible for any load level.

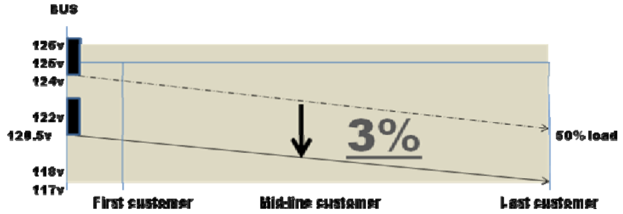


Feeder Voltage Profile (CVC Application)
FIGURE 4

More importantly for the subject of this paper, the tapchanger might be required to change the bus voltage by 7 volts over a daily load cycle. With the common LTC step range of 5/8%, this could create 24 tapchanges (assuming a smooth daily load cycle and a low minimum load).

As an example of CVC effectiveness, Figure 5 illustrates the result of the CVC application during a 50% load condition. The upper profile is the common setting (Figure 3) and the lower profile (Figure 4) is the CVC application at half-load conditions.

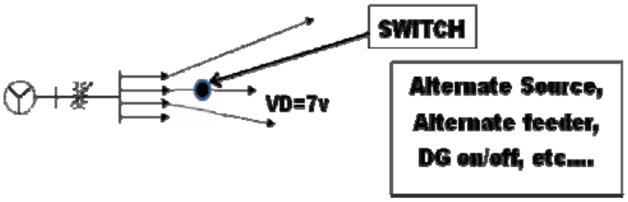
As shown, the CVC application reduces the <u>total circuit voltage</u> level by 3%. An important point for this application is that although the reduction in KW loads is only half as much as a 3% reduction at full load, the var requirements of the thousands of transformers on a distribution system are affected at all load levels. These var flow reductions are <u>very important</u> for circuit voltage control and circuit efficiency.



CVC Effect at Half-Load
FIGURE 5

3) Pre-SG CVC Application

In distribution system applications where a correlation of lowest AOR customer voltage and the load current through the tapchanger device is determined, most modern voltage LTC controls have a feature to implement the CVC as described. This feature is called LDC-Z and linearly adjusts the source voltage level as the load increases or decreases. The setting is as simple as setting the maximum full load AOR voltage drop.



Additional Solutions to CVC Effectiveness
FIGURE 6

Figure 6 illustrates that many options are available to increase the effectiveness of CVC on a distribution system. If the largest voltage drop customer, section or feeder is removed from the LTC's AOR by any means, the next limiting location will become limiting. If that location limit is 2% (2.4V) lower than the removed one, the entire remaining circuit voltage can be immediately reduced by 2% or 2.4V. In this example, the change could be an added line regulator or any of those conditions depicted in Figure 6. As seen by comparing Figures 3 and 4, the number of LTC or regulator tap changes required for CVC application is lower as the maximum AOR voltage drop is reduced.

The CVC function examples described have been applied to a stable radial system. There are many additional distribution system changes that can be made to maximize the effects of CVC. These include load transfers, distribution system configuration changes and the addition of system equipment. Since these are some of the same SG tools for integrating DG into the system, increasing distribution system reliability, minimizing outages and reducing energy costs, the integration of these functions will be challenging.

Any system configuration change, made for any reason, usually affects the AOR of a tapchanger device and will affect the tap operations and duty of LTC transformers and regulators.

IV. REVERSE POWER OPERATION

Several distribution operating conditions can create reverse power flow in an LTC transformer or voltage regulator. If reverse power is experienced on any circuit with tapchangers, care must be taken to ensure the reverse power control actions are appropriate. These operations and system IVVM coordination differ widely for the radial reverse feed condition or multiple source applications.

If no action is taken, the reversal of the primary source direction (reflected in power reversal) will result in the tapchanger operating to one end tap limit (+16) or the other (-16). With normal voltage variations occurring during this condition, the tapchangers may alternate running to both ends of their ranges (32 tap changes). This action has a large detrimental effect on both system voltages and tapchanger duties.

Figure 7 illustrates two individual substations (system source substations) with a possible interconnect for alternate feed (C) and with one feeder DG (D) available. Refer to Figure 7 for the following on variations in possible system configurations or operating conditions.

The typical LTC/regulator control settings referred to below include:

“BLOCK”: The action of the control with this setting is to block any tapchanges as long as the power is reversed.

“IGNORE”: The action of the control with this setting is to ignore the condition of power reversal and continue to regulate voltage in the assigned forward (load side) direction.

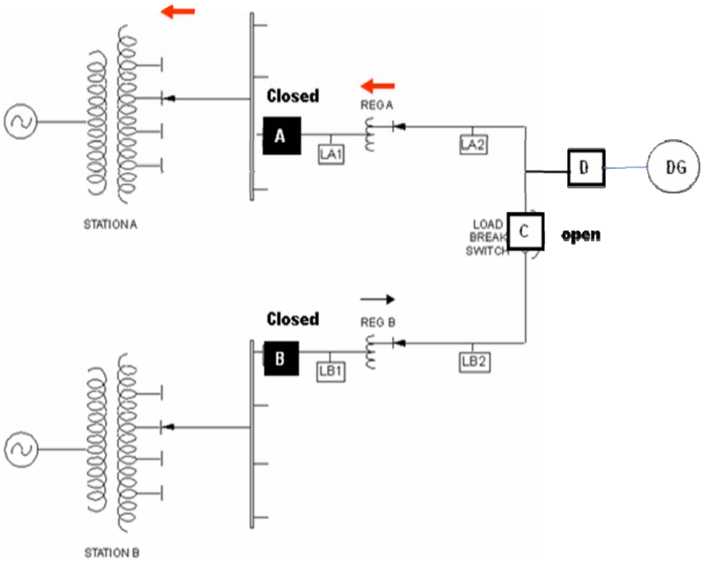
“REGULATE-IN-REVERSE”: The action of the control with this setting is to regulate the voltage on the opposite side (source side) from the forward (load side) direction. The control may operate on measured or calculated source side voltage and will reverse the lower and raise tapchanger action.

“RUN-TO-NEUTRAL”: This setting is used only in applications where the reason for the power reversal cannot be determined at the control location and available communicated information is insufficient. The action of the control with this setting is to run the tapchanger to neutral position and “BLOCK” further operation for as long as the power is reversed.

A. System Configuration Case Examples

Although the following cases are explained from the radial example of Figure 7, the purpose is to expose the same conditions that will exist in the possible SG distribution system of Figure 2.

Case 1: Normal radial operation: A/B closed, C/D open.
All LTC transformers and regulators operate in the forward direction – no reverse operation possible.
RESULT: Base case for LTC operations.



Possible Reverse Power Conditions — Examples
FIGURE 7

Case 2: Alternate feed operation: B/C closed, A/D open.
Reverse power at REG A location – set to “regulate-in-reverse”.
RESULT: Increased tapchanges. With the regulator initially stepping up the load side voltage (Tap +12), the reverse regulation duty would likely have to step up the source side (Tap -12). This action would require a rapid 24 tap change. Due to the extended length of the resultant feeder, additional tapchanges will be probable for subsequent load changes.

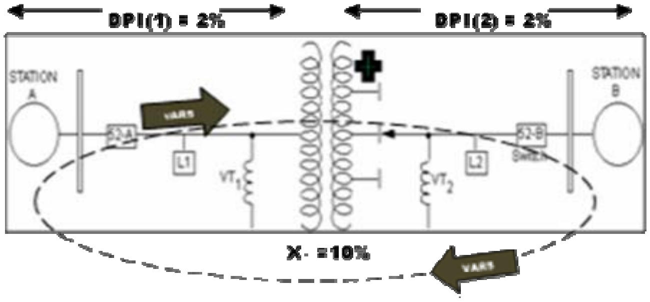
Case 3: DG active: A/B/D closed, C open.
Possible reverse power in REG A and station A transformer.
For relatively small DG capacity, the DG is not capable of nor set to regulate the voltage or to supply vars to the distribution system. In this application, the control is set to “ignore” the power direction change and continue to regulate the line voltage from the power system.
RESULT: Increased tapchanges. Fluctuations in the DG output will affect the distribution line voltage. Depending on the magnitude and timing of these voltage changes, the LTC and regulator may have increased numbers of tapchange operations.

Case 4: Automatic transfer with and without DG operational: With a configuration as shown in Figure 7, the possibility of an automatic alternate feed operation could exist. If the DG is active, the power flow reversal at REG A and REG B locations could be occurring due to the radial alternate feed of Case 2 or the DG contribution of Case 3. Since the desired settings and operation are different depending on the reversal cause and local information is insufficient, the setting must be “RUN-TO-NEUTRAL”.
RESULT: Benefits of the LTC or regulator are compromised and ineffective during these conditions.

Case 5: Alternate feed with active DG: B/C/D closed, A open.
Reverse power in REG A – set to “regulate-in-reverse” (see Case 2).
Reverse power possible in REG B – set to “ignore” (see Case 3).
Note that if an LTC or regulator is located at point D for DG bus regulation, it should be set to “ignore” to continue to regulate the bus from the power system regardless of power direction.
RESULT: See appropriate Cases 2 or 3 above.

Case 6: Large Var Capable DG (Tapchanger in a network):

Figure 8 illustrates the results of operating a tapchanger in a network with additional var capable generation. The example system is an LTC transformer between two independent sources or generators. The example LTC transformer has an impedance of 10% on its own base rating. The example driving point impedance to generation on either side is 2% (same base).The tapchanger consists of +/- 10 - 1% taps.



Tapchanger in a Network
FIGURE 8

The example desired operation is to operate the tapchanger to raise voltage V2 (on right) by one percent (1%).

When a 1% tap is taken, as shown by the **+** sign in Figure 8, the inserted 1% tap V creates a system var flow and voltages shown here:

Ivars = (1%)V / (10+2+2=14%)Z = 7.14%

(7.14%) Ivars X 2%Z = 0.143% = V2 voltage increase

(7.14%) Ivars X 2%Z = 0.143% = V1 voltage decrease

(7.14%) Ivars X 10%Z = 0.714% = V2 Transf voltage drop

Total circuit voltage drop = 1% = Single tap voltage

These calculations show that, on this circuit, 7 (seven) one percent taps would be required to change the V2 voltage level by one percent. These tap changes would also lower the V1 voltage by an equal amount of one percent.

This example illustrates the effect on system var flows of tap changes in a network system (or one with a relatively large var-capable DG). It also illustrates the excessive tapchanger duties that could be imposed should a distribution system configuration be changed to a network application to achieve greater SG benefits.

Note that Case 6 is not affected by the direction of power flow and can have var flow in either direction dependent on LTC tap positions.

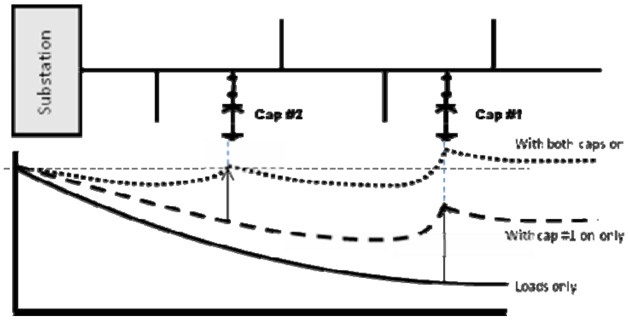
V. CIRCUIT VAR CONTROL

Distribution circuit var control is primary to all the IVVM objectives and has a direct effect on all distribution tapchanger operating duties. For the most part, examples in this paper have assumed the proper operation of available distribution capacitor banks.

Since the X/R ratio of typical distribution feeders can be 3 to 5 or more, the effect of voltage drop due to var flow is large. For example, if a circuit has a 1% voltage drop due to kW load, an equal kvar of load will cause 3- 5% of voltage drop.

Since the X/R ratio of a transformer can be up to 40 or 50, a measure of kvar load voltage drop will be 40-50 times that of an equal amount of kW load. As the transformer kvar loads fluctuate, the resulting voltage changes require LTC tap operations.

A later example will illustrate a pre-SG system coordination technique for minimizing distribution transformers var flows that has reduced LTC transformer and regulators by 50-75%.



Capacitor Bank Effect on Voltage Profile
FIGURE 9

Figure 9 illustrates the effect of distribution capacitor banks on the voltage profile of a radial circuit or feeder. Each capacitor installation reduces the reactive current back to the source. This raises the voltage profile on the entire circuit. Figure 9 shows a voltage rise on the circuit just upstream from each installation. This increase is due to the capacitor bank creating a leading power factor with a typical voltage rise, until the power factor again becomes lagging.

A. Capacitor Banks

Capacitor banks continue to be the most effective method of locally supplying system load var requirements. Traditionally, fixed (unswitched) banks are used to offset minimum load requirements, with switched banks added for load variations.

These banks are best located as near the load var requirement as practical and cost effective, and are found both on feeders and on distribution substation busses.

The basic premise of distribution capacitor bank use is that adding capacitors to the circuit reduces the current in the entire circuit back to the supply source for the vars. This current reduction causes a reduction in I^2R (power losses), a reduction in I^2X (added var load), and a reduction in voltage drop in the system; thereby increasing the capability of existing equipment to carry power (kW).

As described earlier, in an inductive circuit, the voltage drop effect of var flow is much greater than that of kW flow. If the vars are compensated for (e.g., supplied) near the source by capacitor banks, the var-caused voltage drop can be reduced to zero. In some cases, the voltage drop from load KW can be offset by adding capacitors to obtain a slightly leading power factor. A slightly leading capacitive distribution system load will not reflect into the transmission system due to large var losses (I^2X) in the source power transformer.

Since unity power factor transformer load on the secondary creates a lagging power factor load on the primary side, consideration can be made to use the distribution capacitors to create unity power factor on the transformer primary. This action relieves the transmission system from var load accumulation from numerous substation loads.

In some locations, distribution bus capacitor banks are used to offset transmission system var needs. This option can increase the station transformer losses due to the higher, leading power factor current. This higher current also decreases the kW carrying capacity of the transformer as well as creating a need for more LTC tapchanges.

B. Innovative Tapchanger Control Operation

Although the latest technology in digital LTC tapchanger controls calculates and communicates watt and var quantities, these quantities are not generally used in the voltage control algorithms. Some innovative control features have been added to a popular tapchanger control. These features assist in the coordination of tapchanger controls and capacitor controls for more effective volt/var management. These features are designed to use the local intelligence concerning system quantities to better provide effective volt/var management. The importance of this operation for this paper can be a large reduction (50-75%) in LTC transformer tapchanges. The logic for this reduction is to initially operate cap banks for voltage and var control—thus minimizing required tapchanger operations.

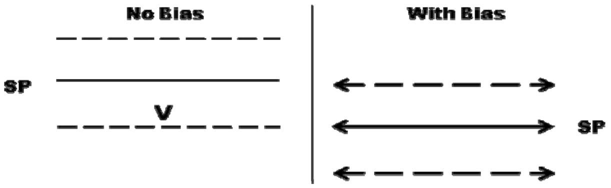
The need for new innovative control actions to reach the stated VVMS goals can again be illustrated using Figure 1. Typical system equipment generally operates to minimize system var flow on a <u>feeder basis</u>. However, in the system in Figure 1, each of the four feeders might have a var load of 600 kvars. The resultant var load on the transformer would be 2400 (4X600) kvars. <u>System</u> var flow is not minimized, since <u>feeder control</u> to unity power factor can only be reduced to half the size of the largest capacitor bank installed. If that bank is a 1200 kvar bank, the transformer could be carrying the 2400 kvar while all equipment is working as designed. The solution to this problem includes expensive (SG) communications to each capacitor bank or some innovative operating techniques. In the case of communication failure, the innovative techniques are again necessary to provide the best operation.

Some of the features of the innovative tapchanger control, which enables additional coordination with other volt/var management equipment, include:

1) <u>The ability to use transformer var flow to adjust or bias the voltage setpoint level</u>

The var bias controlling variable is the measured load var current in the local transformer or regulator. The var bias works to minimize the tapchanger var flow by creating conditions that cause the downstream system capacitor banks to operate earlier than they might otherwise tend to, creating near unity power factor <u>system</u> loading [3].

The var bias action is illustrated in Figure 10. The left side of Figure 10 illustrates the unbiased LTC control settings. The SP represents the voltage setpoint level and the dashed lines represent the band edges or the SP +/- half the bandwidth setting. As described earlier, when the voltage (V) goes higher or lower than the band edges, a timer starts toward a tapchange operation. The right side of Figure 10 illustrates the control with a “lower” control setting bias. With the bias in effect, the voltage must reduce slightly further or delay a little longer (than with no bias) to initiate a tapchanger “raise” action. As described later, this lower bias would be enacted for a lagging power factor load.



Var Bias Action
FIGURE 10

The setpoint level is determined by the maximum capacitor bank size downstream of the tapchanger control.

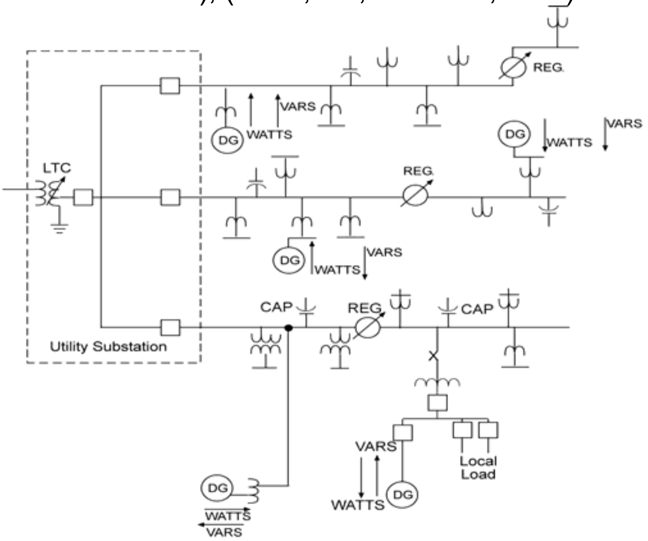
2) <u>The ability to calculate var losses in LTC transformers for power factor targeting on the primary side</u>

The algorithm to calculate the loss of vars in a transformer is very simple: Vars = I^2X. By inputting the transformer impedance and measuring the current, the losses are easily estimated. This calculated value can be added to the measured var flow value on the secondary. The var flow target then becomes zero vars on the transformer primary side.

VI. EFFECTS OF DG

The types of distributed generation found in an SG distribution system include the following:

a) Induction (requires var source – wind)
b) Synchronous (internal combustion, small hydro, gas turbines)
c) Asynchronous (with converters), (Solar, PV, fuel cells, wind)



High Penetration DG Example
FIGURE 11

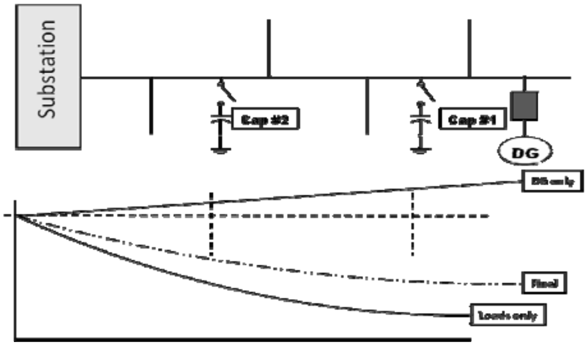
A. Small Distribution System DG Applications

The possible system effects of distribution system DG is dependent on the type of DG, the location on the circuit and the scheduling of operation. If more than one type is applied, coordination of all these factors must be established. Figure 11 illustrates a radial distribution system with a high penetration of various DGs. The different DG types can be indicated by the power and var directional flow associated with each one in the figure. Except with auxiliary var support equipment, the induction type DG cannot supply vars to the circuit. In general, at this time, distribution DG is not generally allowed to supply vars to the circuit because of the complications to circuit voltage control.

Figure 11 shows:

a) One supplying LTC transformer with three circuits or feeders, each with some DG installed. One DG (bottom circuit) is shown to have an associated load bus with breakers.
b) Line regulators installed on each feeder.
c) Several line capacitor bank installations.

Comparison of Figure 9 and Figure 12 illustrates the large voltage profile change difference between the distributed var supply of capacitor banks and the distributed power supply of DG. As stated previously, this is a result of high X/R ratios on distribution circuits.



DG Effect on Voltage Profile
FIGURE 12

As in Figure 9, the line "loads only" indicates the voltage profile with no capacitor banks or DG on the circuit. If the DG supplies only kW to the system (or replaces kW load) at a single point as compared to accumulating down the feeder, the resultant voltage change is a straight line. This is indicated as the "DG Only" line in Figure 12. The resultant voltage of loads and DG is the sum of the two effects and is shown as the "Final" line.

The complexities of circuit voltage control may be inferred by considering the interaction of the many voltage controlling factors of Figure 11 or Figure 2.

B. Large DG Installations

Large DG step-down transformer installations, like wind farms, can create various LTC transformer duty cycles. These duties depend on the DG type (described earlier), the local bus loading and the methods of var control or voltage control on the bus.

Usually this application dictates voltage control from the power system by the step down transformer. In that case, the LTC control setting should be set to "Ignore" as described in Section IV "Effects of Reverse Power Operation." The duty is largely defined by the source of required vars for operation, the size of the generation and the range and frequency of load/ generation cycling. It also should be noted that the high transformer X/R ratio causes a much greater voltage fluctuation with changing var loads than changing kW loads.

VII. CONCLUSIONS

LTC transformers, line regulators and Volt/var Management systems equipment in general perform a critical function on every power distribution system. As Smart Grid technology is expanded and integrated into the power system, equipment coordination will become more challenging. The plan is to maintain this coordination and increase the flexibility of operation with a vast increase in communication capability. These communications will provide the necessary system information for making the most efficient system operating decisions and for providing operating control of system equipment.

This paper has focused on the changing LTC and regulator duties as the SG is integrated into the distribution system.

Conservation voltage control (CVC) is one of the highest profile SG conservation features that have a significant effect on LTC transformer and regulator duties. The act of regulating minimum voltage at the customer location rather than maintaining substation bus voltage is shown to substantially increase these duties.

The effects of power reversal in portions of the distribution system are illustrated in several applications. The results, depending on application, are shown as: a) minimal additional duty, b) substantial additional duty to provide additional circuit voltage control, c) duty increasing conditions requiring multiple immediate tap operations to d) operations that have a detrimental and possible damaging effect on the distribution system voltages and may cause “hunting” for proper tap position.

Distribution circuit var control is primary to all IVVM objectives. As described, the proper operation of distribution capacitor banks will substantially reduce the number of required tapchanger operations. The challenge will be to accommodate the myriad of possible dynamically changing distribution system configurations.

The effects of induction, asynchronous or synchronous types of DG on distribution systems can be quite varied. Since, at this time, distribution system DG is not generally allowed to provide reactive power; the effect of operation is shown to be a reduction in tapchanges. Increased tapchanger requirements will be generated if system configurations change and tapchangers are required to compensate the resultant voltage changes.

Several other factors can change the duty cycles of LTC transformers and regulators. Illustrated in this paper are the effects of the placement of distribution feeder regulators and the effects of different LTC transformer source-side impedances or fault duties.

If the LTC transformer control operates as a slave to a “Smart Grid Control,” it must also have the capabilities to safely and efficiently operate without communications. It may be possible to assign the LTC and regulator controls as a “Local Smart Grid control” with communications directly to local area equipment (in addition to the “Smart Grid control”). This would provide more flexibility, security and greater reliability under all operating conditions.

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BIOGRAPHY

E. Tom Jauch is a Utility Power System Consultant for Beckwith Electric Company, Inc. His consulting practice involves projects relating to T&D power system studies and equipment applications and training. Jauch has more than 47 years of experience including 20 years as a senior application engineer and manager of business development for General Electric's Electric Utility System's Engineering Department located in Schenectady, New York. Jauch is a former instructor in the Graduate School of Electrical Engineering at Rensselaer Polytechnic Institute and Union College in New York as well as Auburn University. He was a senior engineer with Central Illinois Light Company (CILCO) for five years. Prior to becoming a consultant, Jauch was Manager of Application Engineering for Control Products and Systems with Beckwith Electric Company. Prior to that, he was an engineering consultant to Beckwith Electric on protection and control product lines. Jauch has a Bachelor of Science in Electrical Engineering from Bradley University in Illinois and has authored numerous technical papers and magazine articles on power transformers, controls, and protective relaying. He is a life senior member of the IEEE, a member of the Power Engineering Society, and is active in the Power Transformer Committee and the Substations Committee.