New York Independent System Operator (NYISO)
Benefits of Adding Capacitors to the Electric System
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Executive Summary

This report identifies several benefits derived from adding capacitors or other sources of VAR support to the distribution system. VAR support added to the distribution system benefits both the distribution and transmission systems. The categories of benefits identified include loss reduction, reduced capacity requirements, dispatch and operational cost reduction, and increased reliability. For each benefit, methods for determining the economic benefit of the improvement are discussed. Also included is an example which focuses on the indicative savings that can be achieved in the NY control area. This document is intended for a broad audience reflecting varying backgrounds and degrees of familiarity with power system engineering. As a result, the presentation of some concepts may seem elementary. An effort has been made to strike a balance between accessibility and brevity.

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1 Introduction

The purpose of this report is to outline the benefits derived from added VAR support on the distribution system and how the VARs on the distribution system impacts the transmission system and illustrate how each of the benefits can be analyzed and quantified.

Most power system loads and delivery apparatus (e.g., motors, lines and transformers) are inductive in nature and therefore operate at a lagging power factor. A power system at a lagging power factor requires additional current flow, which results in reduced system capacity, increased system losses, and reduced system voltage. The shunt capacitors are classified as negative reactive load (delivers positive reactive power to the system) and they operate at leading power factor. This will decrease the reactive power flow on the supply lines and the kVA supplied by the generators and from line capacitance. Adding capacitive support as close as possible to the inductive portion of the load will help to minimize reactive power flow, minimize losses, and improve the voltage profile of distribution feeders and transmission supply.

Local voltage support, even at the distribution level, can improve grid reliability and security for transmission users. However, a utility cognizant of only the local benefits of an improvement may be reluctant to enact a change that improves operations for all users if the costs and benefits are not made transparent and a fair distribution of the costs borne by all that benefit. In the case of adding capacitive VAR support to the system, the reliability benefits can be enormous if the improvement dramatically improves the voltage security of the transmission system. However, such improvements are unlikely to be undertaken if the local benefit due to loss reduction is not significant to the load serving entity.

Figure 1 shows how the shunt power capacitors increases system capacity and reduces system losses by reducing the VAR flow through the transmission network. S1, Q1, S2, and Q2 are the source generated apparent power and reactive power before and after adding the capacitor. Qcap is the size of the added capacitor bank and P is the load active power.

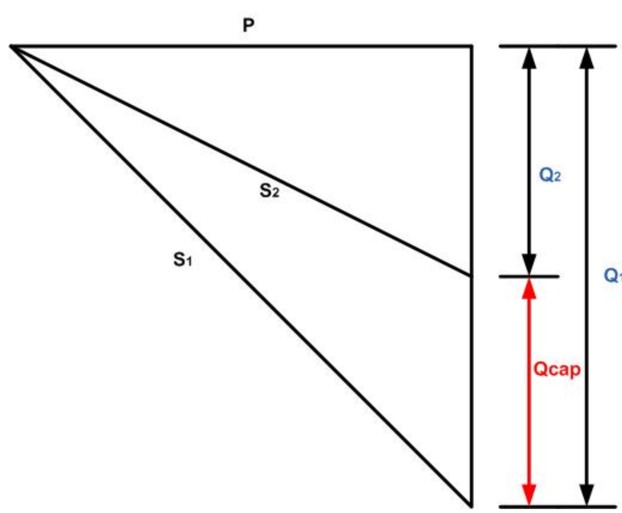

Figure1 power triangle representation of the shunt capacitor effect on the system

2 Benefits of Capacitive Support

Table 1 summarized the benefits of using shunt capacitors for transmission and distribution systems. Reducing system power losses and improving feeder capability (equipment capacity requirements) are the primary benefits for a distribution system. Reactive power (VAR) support and voltage control are the primary benefits for a transmission system.

Benefits	Transmission system	Distribution system
Reduce system power loss	secondary benefit	primary benefit
Reduce system/equipment capacity requirements	secondary benefit	primary benefit
Reduce operating costs by relieving dispatch constraints and improving voltage control	primary benefit	secondary benefit
Increase reliability, reduce risk of voltage problems and blackouts	primary benefit	primary benefit

Table 1 Benefits of installing shunt capacitors

Of these four areas of benefit, two areas, the impact on system losses and impact on capacity requirements, can be studied with power flow analysis and a limited amount of economic data. An Optimal Power Flow model can also be employed to identify locations for improvement as well as optimal levels of compensation. However, in order to study the benefit derived from impacts on system dispatch, the OPF should be used to mimic the market dispatch of the system. This requires more detail in the power flow model and much more economic data and assumptions. Analyzing the benefit of increased reliability requires application of steady-state stability programs such as those used to determine AC transfer capability, as well as additional assumptions concerning the measurement of risk. The following sections describe each of these benefits and analyses in more details.

2.1 Loss Reduction

One benefit of adding capacitive support to the distribution and transmission systems is a reduction in losses. When the load power factor is low, larger current is needed to deliver the same amount of real power to the load than when the load power factor is close to unity (1pu). Higher currents create higher thermal (I^2R) losses in the resistive elements of the network than lower currents would.

One recent common example of the application of capacitors for loss reduction concerns the increasing need to compensate for reactive losses in substation transformers. This problem has been the result of the inclination of utilities to overload their distribution substation transformers. For example, a utility purchases a transformer back in the 70’s with a triple rating (OA/FA/FOA). To reduce some of their concern for their growing short circuit levels they purchase a transformer with a higher than normal impedance. In their effort in the late 90’s to reduce cost, they decided to load these transformers according to the loading guides instead of the more conservative approach of the past since transformers rarely fail due to overload. The problem is this: if we assume a 30/40/50 MVA transformer at 14% impedance and loaded up to 130%, this transformer will have over 12 MVARs of losses. At 100% of rating the losses are about 7 MVAR. Of course the obvious solutions to this issue are: load transformers conservatively, purchase lower impedance transformers and refrain from purchasing triple rated transformers. The downside to these approaches is increased initial cost and higher short circuits.

Any losses on the distribution system contribute to the load plus losses that will be carried on the transmission system adding more stress to the transmission system, especially under outage conditions. For example, if the load in the down state region of the NYCA is generally supplied from generation in the upstate and western regions of the NYCA, and the reactive portion of the load and losses are not compensated on the distribution system, then the reactive load and losses need to be supplied by the generators so there is additional loading on the transmission system along with potentially lower voltages. This may limit the flexibility and robustness of the transmission system for the operators of the system.

To put this in perspective, the resistance R decreases when conductor diameter increases and the reactance X increases as the required geometry of phase to phase spacing increases. And since the VAR loss increases in proportion to the square of the total current, depending upon the value of X, the VAR loss on the transmission system is approximately 2 to 25 times larger than Watt loss. Typical ratios are:

- 138kv lines, X = 2 to 5 times larger than R
- 230kv lines, X = 5 to 10 times larger than R
- 500kv lines, X = 25 times larger than R

In order to quantify the benefit of a reduction in losses resulting from additional capacitive support it is necessary to estimate both the reduction in losses (MWH) and the value of energy ($/MWH) over the time period of interest (1 –year, 5 –year). The reduction in losses can be computed directly for radial distribution systems but is best accomplished by comparative AC power flow analysis for more parallel distribution networks and transmission systems. Since an improvement in distribution voltage profiles can also result in an increase in metered demand, which will result in an increase in corresponding real power losses, it is important to consider the demand model and the voltage dependence of the load. The loss reduction measured will also depend upon the selection of generation slack to back-off as a result of the improved load power factor, so engineering justification and diligence in running the simulations is required.

The ratio of the system losses associated with the local load, with and without capacitors installed, can be estimated with the following formula. The formula assumes constant kilowatt and constant voltage at the load.

$$\textit{loss}\ \text{ratio} = \frac{\text{Loss with Capacitors}}{\text{Loss without Capacitors}} = \left(\frac{\text{existing } \textit{Power} \text{ Factor}}{\text{corrected power factor}}\right)^2$$

The value of loss reduction in each time period is equal to the product of the quantity of loss reduction with the price. If the time horizon of the study is more than a year, future cash flows should be appropriately discounted to obtain the present value of the savings. Since the reduction in losses is likely to vary hourly with loading, as well as daily and seasonally, more accurate estimates can be achieved by breaking the time period of interest down into finer increments and using a distinct energy price for each increment, representative of the expected LBMP for each respective increment.   Although in the LBMP market, the value of energy varies by location as well as with time, for the purposes of estimating the economic benefit derived from the impact of additional capacitors, using an average LBMP is preferable than relying on location specific forecast LBMP for two reasons – first, it is often not certain which transmission location and LBMP to associate with distribution level capacitor additions; and second, congestion is difficult to forecast accurately and the assumption of high or low prices due to congestion can lead to significant over or under statement of the value if the congestion does not materialize. However, LBMP and other sensitivities derived from the AC load flow and OPF are useful for identifying the best locations to add capacitors and can be used in separate analysis to better understand the benefits of various planning scenarios.

2.2 Reduced Capacity Requirements

Another primary benefit of reducing the reactive loading and reactive losses on the distribution system is the potential of reduced equipment sizing and lower generation capacity requirements and more flexibility and capability for switching on the distribution system. Identifying specific instances of reduced sizing of individual equipment is difficult and hence establishing an economic value to the phenomena is very uncertain. However, the reduction on losses translates directly to a reduction in system capacity requirement, for which a price is established by the market. Hence, an estimate of one benefit of additional capacitive support can be obtained by multiplying the installed capacity price by the reduction in capacity requirement for each zone. For this calculation, the capacity prices corresponding to the appropriate capacity zone should be used.

Having less loading on the distribution feeders as the result of having less system losses and less reactive loading may add additional flexibility for switching load among feeders, better voltage profiles, and especially, if and when, "Smart Grid" components are added to the distribution system.

Traditional guidance states that the optimum economical power factor for a system, with regard to released capacity only, can be estimated by use of the following formula[1]:

$$PF = \sqrt{1 - \left(\frac{C_i}{S_i}\right)^2}$$

Where:
C is the cost per kilovar of capacitor bank
S is the cost per kilovoltamperes of system equipment
PF is optimum power factor

The formula compares the cost of capacitor banks to the cost of transformers, regulators, etc., as alternative means of providing increased system capacity. The graph of the formula, the optimum power factor as a function of the cost ratio of the capacitor bank versus other system equipment, is illustrated in figure 2[2].

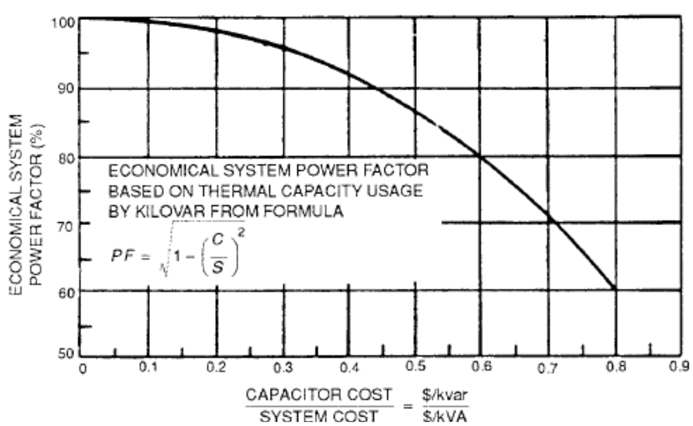

Figure 2 Economical system power factor

The power factor required to release a desired amount of system kVA can be determined by the following formula:

$$PF_{mew} = \frac{PF_{old}}{1 - kVA_{release}}$$

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[1] IEEE Std 1036-1992, "IEEE Guide for Application of Shunt Power Capacitors"

[2] IEEE Std 1036-1992, "IEEE Guide for Application of Shunt Power Capacitors"

Where:
PFnew is the corrected power factor
PFold is the existing power factor
kVArelease is the amount of kVA to be released (in per unit of existing kVA)
The annual benefits due to released generation, substation, and transmission capacity energy can be calculated using the following formula:

$$\Delta\$ = \underbrace{\Delta S_s \times C_s \times i_s}_{\textit{Substaion}\ \text{benefits}} + \underbrace{\Delta S_T \times C_T \times i_T}_{\textit{T}\text{ranmission benefits}} + \underbrace{\Delta S_G \times C_G \times i_G}_{\textit{G}\text{enerator benefits}}$$

Where:

$\Delta S_s, \Delta S_T, \Delta S_G =$ Released substation, transmission, and generation capacity respectively due to capacitor installation

$C_s, C_T, C_G =$ Cost of substation, and associated apparatus, \$/kVA, transmission line and associated apparatus (\$/kVA), and cost of generation (\$/kW) respectively

$i_s, i_T, i_G =$ Annual rate applicable to substation, transmission, and generation respectively

2.3 Dispatch and Operational Benefits

Increased reactive power support has the potential to alter the binding dispatch constraints, impacting the day-ahead market and real-time balancing market. For instance, the interface stability limits in the NYISO can be set by voltage stability or transient stability limitations, both of which are impacted by reactive power support.

A commonly used formula to estimate the voltage rise that capacitors will produce is as follows:

$$\Delta V = \frac{(k\,\text{var})}{10(kV)^2} X_L$$

Where:
ΔV : is the percent voltage rise at the point of the capacitor installation
kV : is the system line-to-line voltage without capacitor in service
kvar: is the three-phase kilovar rating of the capacitor bank
XL : is the inductive reactance of the system at the point of the capacitor installation, in ohms

A change in an interface limit during constrained periods has a direct impact on the total cost to dispatch the system for those periods. A linear estimate of the benefit is the product of the shadow price for the constraint with the change in the constraint limit. However, that estimate is only linear and applies only to the case in which the constraint is binding both with and without the reactive power improvement. It is possible that a transmission improvement could totally eliminate the constraint and that a different transmission constraint could become binding. For instance, if the voltage stability constraint is relived, a thermal limit at a higher interface flow may become binding. Over many time periods, the transmission improvement can change the dispatch and LBMP and eventually expectations about LBMP influence the behavior of market participants. The benefit derived from the transmission improvement can be measured from the perspective of the ISO or individual market participants. From the ISO perspective, the benefit is realized in a reduction of system operating costs based on the objective function of the real-time dispatch program. For individual participants, the benefit or harm in each interval is measured by the change in LBMP multiplied by the participant's position at each location. The total benefit is calculated as the summation over the time horizon of the benefits realized in each dispatch period. Over very long time horizons, the transmission improvement has the potential to influence the site selection of new generation or demand side projects.

Increased capacitive support may also result in other operational benefits. For instance, increased VAR support could reduce the duty cycles required of LTCs on both the distribution and transmission systems. Additionally, increased capacitive support could reduce the VAR output of generation and reducing wear and tear on generation excitation systems and decrease the frequency of encountering maximum VAR limits. Analysis of these benefits requires both accurate OPF modeling of the dispatch program as well as understanding of the local operating characteristics.

The revenues to the utility are increased as a result of increased kWhr energy consumption due to the voltage rise produced on a system by the addition of the corrective capacitor banks. This is especially true for residential feeders. The increased energy consumption depends on the nature of the apparatus used. Table 2 gives the additional kWhr energy increase (in percent) as a function of the ratio “m” of the average voltage after the addition of capacitors to the average voltage before the addition of capacitors (based on a typical load diversity) [4].

M	1.0	1.05	1.1	1.15	1.2	1.25	1.3
ΔkWhr % increase	0	8	16	25	34	43	50

Table 2 Potential increase in metered demand with improved voltage profile

2.4 Reliability Related Benefits

The previous section addresses the benefit of improved voltage control and VAR support on the cost of operating and dispatching the power system. That benefit can be directly measured by a reduction in operating costs. However, increased VAR support and voltage control also increases the reliability of the system and reduces risk.

In power systems the reactive power and the voltage are coupled quantities. Capacitor banks are typically installed on the transmission system at major buses to provide voltage support for the power transfer through out the area. They are also installed at distribution buses and directly on customer delivery buses to provide voltage support to smaller areas and to individual customers. Capacitor banks installed on distribution lines support voltage along the entire length of line.

When reactive power supplies are exhausted, it is possible for a system to experience a catastrophic voltage collapse blackout even in circumstances when there is an abundance of generation. Although wide area blackouts are rare, local load shedding events to maintain voltage stability are somewhat less infrequent. Increasing the capacitive support at transmission and distribution levels reduces the reactive power load required of generation and increases operating security margins. In other words, capacitive support decreases the likelihood of experiencing blackouts or load shedding events.

Quantifying the benefit derived from increased reliability has been calculated by two fundamental, complimentary approaches, Monte Carlo simulation and Security Margin calculation. The application of Monte Carlo simulation to value improved reliability is similar to typical Loss of Load Probability (LOLP) and Expected Un-served Energy (EUE) calculations. Starting from a base case load flow, patterns of load, generation, and outages (generation and transmission) are specified. Random draws determine demand, available generation and transmission for a single power flow case. Each case is solved both with and without the potential transmission addition. Distribution improvements are reflected by the power factor of the bus loads while transmission improvements can be modeled directly in the power flow transmission data. For each solution, the un-served energy is recorded. For instance, if the case was unsolvable, the entire demand is considered un-served load. However, if the case was solvable subject to load shedding, the portion of load shed is bookmarked as un-served energy. After running very many samples, a frequency distribution of un-served energy is obtained for both the un-improved and improved networks. The distribution corresponding to the capacitor addition can be compared with the original distribution and any statistical measure can be used to characterize the improvement in un-served energy. For instance, one might look at the change in the expected (mean) un-served energy or the change in the 95th percentile of the un-served energy distribution. However, a dollar value is most useful for comparison with the costs associated with the project. By multiplying the un-served energy with a value-of-lost-load, usually something in the neighborhood of $1000/MWH, the distributions can be translated into reliability cost distributions. Commonly, the expected reliability cost (i.e. mean of the distribution) is compared between the improved and un-improved cases, although other measures, such as the change in the 95th percentile or 99th percentile is used for comparison similar to financial "value at risk" calculations.

The **Security Margin** approach attempts to reduce the computational burden associated with Monte Carlo methods as well as eliminate model bias in the underlying specification of the universe of events. The computational burden is reduced because a frequency distribution is assumed rather than arrived at empirically. The Monte Carlo method is thus complimentary to the Security Margin method. The Security Margin method first establishes the distance the base case systems are from critical points at which secure operation is no longer possible. For instance, the base case could be the 95th percentile demand from the load duration curve. The security margin at that loading is found by computing a sequence of load flow solutions corresponding to ever increasing levels of stress similar to typical transfer capability computations. The stress can be combinations of load and transfer increases, as well as generator outages, and branch element outages. It is appropriate to include several different stress scenarios. The security margins are calculated both with and without the proposed improvements (typically an iterative process is employed to refine site selection) to establish the improvement in security margin derived from the transmission improvement. Again, the changes in the margin are one measure of the improvement derived from the additional VAR support. However, the changes in margin can also be associated with un-served energy by applying the assumed demand probability distribution. Once the expected un-served energy is calculated, the dollar benefit of the reliability improvement is then calculated as it was for the Monte Carlo approach. This approach is described in greater detail at the end of this report.

3 Examples Quantifying the Loss and Dispatch Benefits of Added VAR Support to the Distribution System.

Case 1: Radial System with distributed loads

Figure 3 shows the configuration of a 13.8 kV radial feeder which could be representative of the overhead feeders in NY. We assume the following values for the financial benefits analysis based on information available to Quanta Technology, the average fixed charge rate is 0.2, the average demand cost is $830/KW, the energy cost= $0.12 /kWhr, the system loss factor is 0.3, and capacitor cost is $13/kVar.

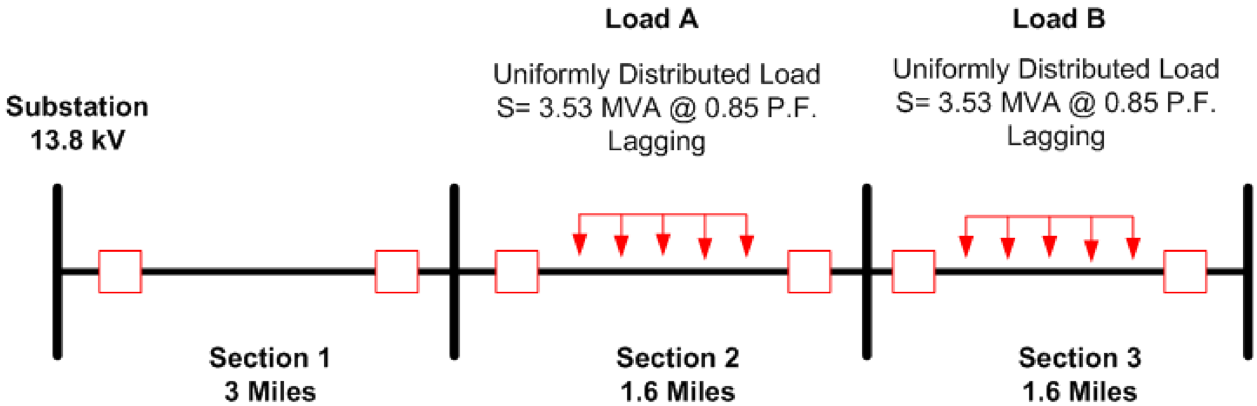

Figure 3 feeder layout (loss factor = 0.3, electricity cost = 0.12 $/ kWh)

A series of studies were conducted to evaluate the effect of reactive compensation on the radial feeder shown in Figure 3. To model the effect of distribution capacitors installation close to the loads the load reactive power were decreased (in steps of 10% with respect to the base case) until achieving a unity feeder power factor, while maintaining the active power component constant. A power flow analysis and distribution loss calculation was performed for each loading condition to obtain Ploss peak, which is the basis of the results presented in this section. The initial power factor of loads used during this simulation was equal to 0.85 lagging which corresponds to a feeder power factor of about 0.77 lagging. Figure 4 shows a plot of the active power losses at peak ($P_{loss\ peak}$) as a function of the feeder power factor. The graph shows that the feeder losses are reduced with the increase of the power factor.

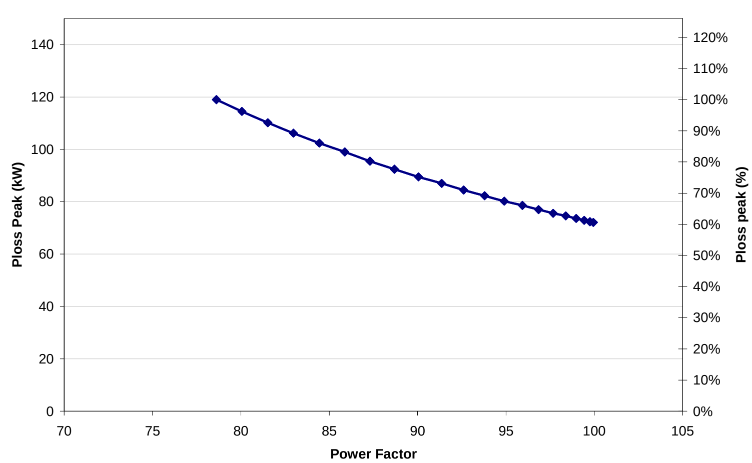

Figure 4 Active power losses at peak (kW, % of base case) versus power factor of typical feeder 1

Figure 5 shows that it is feasible to reduce losses by about 30% (which represent approximately $ 14,600 per year) by improving the feeder power factor from 85% to 100%. This reduction can be achieved by installing about 3,346 kVAR with a total cost of approximately $ 43,500. Installing capacitors also leads to a reduction on the feeder peak loading (kVA), which helps deferring or eliminating capacity investments. Installing capacitors also leads to a reduction on the feeder peak loading (kVA), which helps deferring or eliminating capacity investments. This is shown in Figure 6, which presents a plot of the feeder peak loading required capacity as a function of the power factor. It can be noticed that the required feeder capacity can be reduced by about 15% by improving the feeder power factor from the base case to 100%.

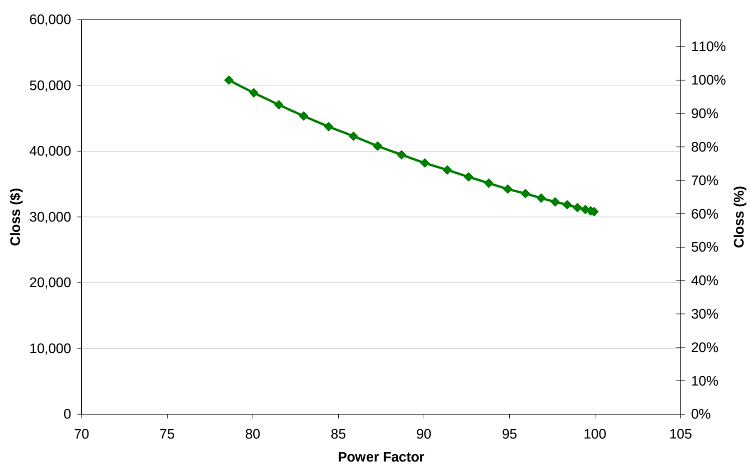

Figure 5 Annual cost of losses ($, % of base case) versus power factor for the radial system

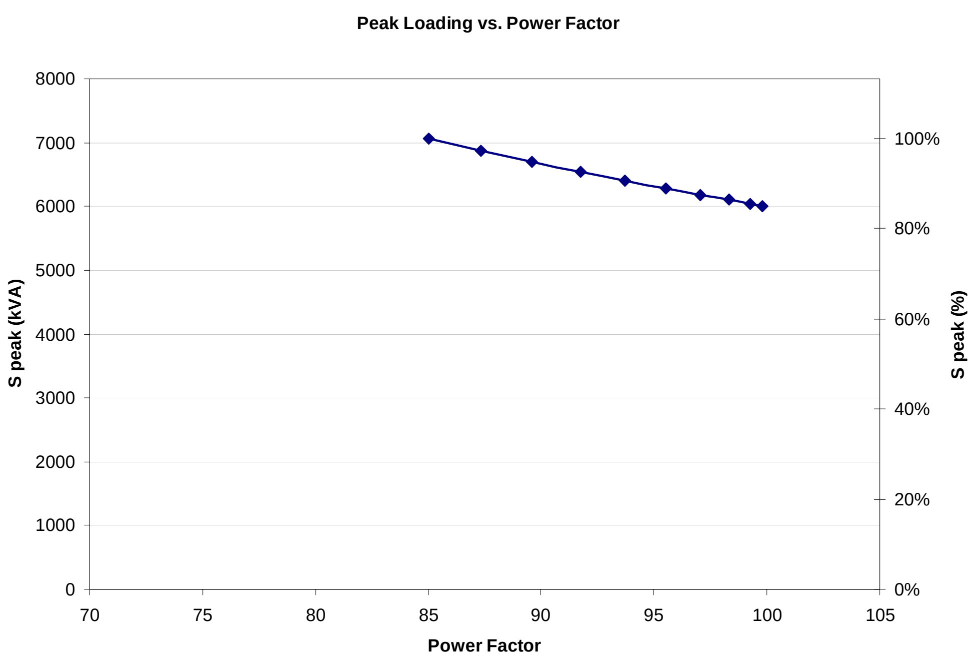

Figure 6 Peak kVA loading (kVA, % of base case) versus power factor of typical feeder 1

Figure 7 shows a plot of the kVAR required for improving the feeder power factor and the corresponding costs calculated by using an average value of 13 $/kVAR for switched capacitors, which is based on a survey performed by Quanta Technology.

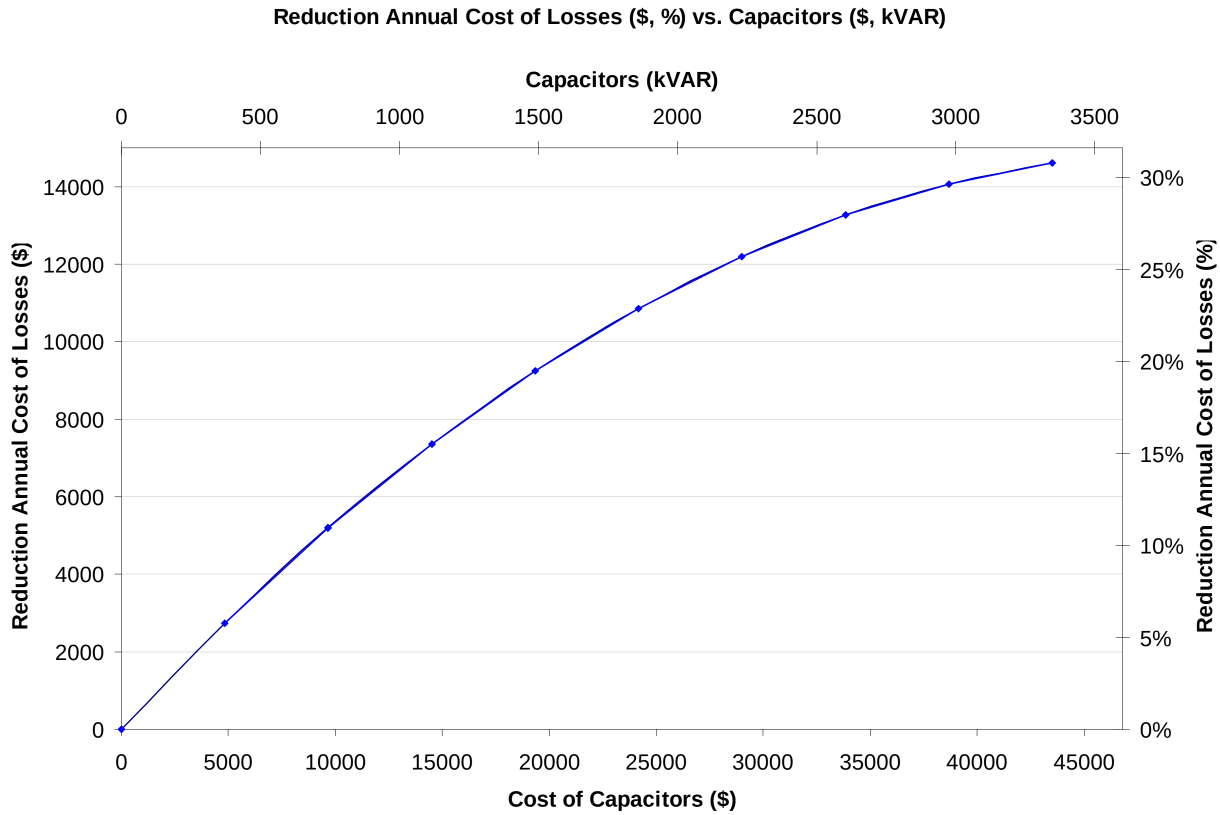

Figure 7 Reduction of annual cost of losses ($, % of base case) versus capacitors (kVAR, $) and power factor of radial feeder

The results of improving the p.f. from 0.85 to 1 are summarized in the Table 3 below:

Benefit	Value
The savings in the system kVA	1047 kVA
Required Capacitor banks Size	3,346 kVAR
Loss reduction	31 KW
Demand reduction	31 KW

Table 3 Benefits of results summary of installing shunt capacitors

The total benefits due to the installation of the capacitor bank can be summarized as:

1. The annual saving due to released capacity (Cs)
   Cs = (demand reduction)(Feeder cost+Substation Capacity increase) per KVA (average rate)
   = (1047 kVA)($ 64.4/kVA)(0.20 /yr)= $13,485 /Year
2. Loss Reduction price (Cl)
   Cl = (Loss reduction)(Number of Hours in a year)(loss factor)(Cost of energy)
   = (31)(8760)(.3)(0.12) =$9,776 /Year
3. Annual Capacitor banks price (Cc) = (Kvar required)(Cost /Kvar) (average rate)
   = (3346)($13 /kVar)(0.20 /yr)= $8,700 /Year
4. Demand reduction annual saving (Cd)
   Cd = (Saving in demand)(average demand cost /kW) (average rate)

= (31KW)(832.5 / KW)(0.20/yr) = $5162/Year

5. Net annual saving =(Cs+ CL+ Cd – Cc) = **$19,723**

This is in addition to the energy (kWhr) benefits.

Example: simple two bus system with concentrated load

This example illustrates how loss reduction and voltage support can additionally improve dispatch costs on the transmission system. Consider again the system shown in Figure 3 above. Assume that the power transfer to the load center is limited by the low voltage at the load (0.95 minimum) or a thermal limit on the transmission line. The demand without transmission losses is 200 MW. Assume that the generator has a cost of $10/MWHr and there is demand side generation (i.e. "behind the meter") without voltage support for 100 $/MWHr. Two cases were simulated, in the first the system was loaded without the shunt capacitors, and the second case a 100 MVar capacitor is installed near the load center. In the case without the capacitor, the transfer from the $10/MWh generator is limited by the voltage drop at the load, so that only 180 MW can be delivered by the cheap generator and the remainder must be made up with the demand side expensive generation. There is 1.5 MW of transmission losses and 21.5 MW are made up at 100 $/MWHr by the demand side power source. In the case with the additional 100 MVARS at the load, the losses are reduced from 1.5 MW to 1 MW and the transfer capability of the line increases from the voltage limited transfer at 180 MW to the thermal limited transfer at 185 MW. In this case then, only 16 MW is provided at 100 $/MWHr. Note that in both cases, the LBMP is still $10/MWHr at the generator and $100/MWHr at the load, so neither the generator or load serving entity are impacted in the market. However, the dispatch cost is reduced by over 12%. Table 5 below compares the system behavior under both operating conditions.

	Pg1	Qg1	Pg2	Demand	Loss	Vp.u. load	Dispatch cost
Without capacitor	180	110	21.5	200	1.5	0.95	3950 $/Hr
With capacitor	185	10	16	200	1.0	0.99	3450 $/Hr
% change	3%				33%	4%	13%

Table 5 Example loss and dispatch benefits from shunt capacitors

This example illustrates that added VAR support can reduce operating costs by reducing losses and changing the dispatch constraints. Note that the reduction in capacity requirement or the reliability benefit is not reflected by this example. This example also illustrates that the benefit depends upon the generator economics. For instance, if the demand side generator was available at 1000 $/MWHr instead of 100$/MWHr, the savings would be even more significant. However, if the demand side generator was available at 20$/MWHr, the savings would be much less. In order to measure the dispatch benefit of any proposed VAR improvement, it is necessary to model the market dispatch.

4 Example Quantifying the Reliability Benefit to the Transmission System of Added VAR Support to the Distribution System.

Capacitors installed on the distribution system can have a significant impact on the voltage stability margin of the power system. An optimization problem can be formulated to evaluate the size and location of capacitor installations and to identify those locations that have the greatest impact on voltage stability. The objective is to minimize capacitor installation cost while increasing voltage stability margin to an arbitrarily specified percentage. The output of the optimization algorithm is the control locations and amounts for both steady state and specified contingencies and the combined control location and amount. For each contingency, the identified controls are switched in, and the voltage stability margin is recalculated to check if sufficient margin is achieved. That process however, does not measure the benefit of improved reliability brought by the increase in the stability margin, which is addressed in this section.

The previous sections outline the benefits and considerations associated with added VAR support. Diligent planning decisions require accounting for all types of benefits and costs associated with candidate transmission improvements. Valuing the reliability benefit presents a significant challenge. This section describes a method for determining the value of the reliability benefit as the change in the risk of experiencing an insecure operating state or a voltage collapse blackout. Risk is used to mean the product of the probability of an event with the cost impact of the event. Risk measurement is particularly difficult when applied to very low probability events with extremely high and uncertain costs.

The method presented here is based on engineering computations that are well understood and implemented within many commercial software packages for transfer capability and voltage security assessment. These computations are used in planning and operating environments to assess the security of the system and identify controls and screen contingencies. However, the valuation also depends upon very uncertain parameters, such as the cost of experiencing a low voltage event requiring load interruption, or the cost of experiencing a system blackout. Fortunately, the calculation with the greatest uncertainty (the cost of experiencing a low voltage security event or a voltage collapse) is decoupled from the calculation of the maximum loading or transfer capability. Thus, the proposed improvement can be evaluated in terms of impact on MW alone as well as for varying assumptions concerning the cost of voltage collapse or low voltage.

The following example explains the calculation of the reliability benefit of improved VAR support. Numerical details are shown in the appendix. Assume that we are interested in measuring the reliability benefit of additional VAR support in the distribution system, realized over a single year period. Figure 9 shows the forecast load duration curve for the demand. The peak demand is 35,000 MW. That means that for 100% of the hours in the study period, the demand will be less than 35,000MW. The 99th percentile is shown to be 34,000 MW, meaning that for 99% of the hours the demand will be less than 34,000 MW. The 98th percentile is 33,000 MW and the 95th percentile is 32,000 MW. There is adequate capacity of generation, but transfer from generation to load is potentially limited by voltage stability. The reliability benefits of added VAR support are realized mostly in the higher demand hours in which reactive power and voltage stability margins are smallest.

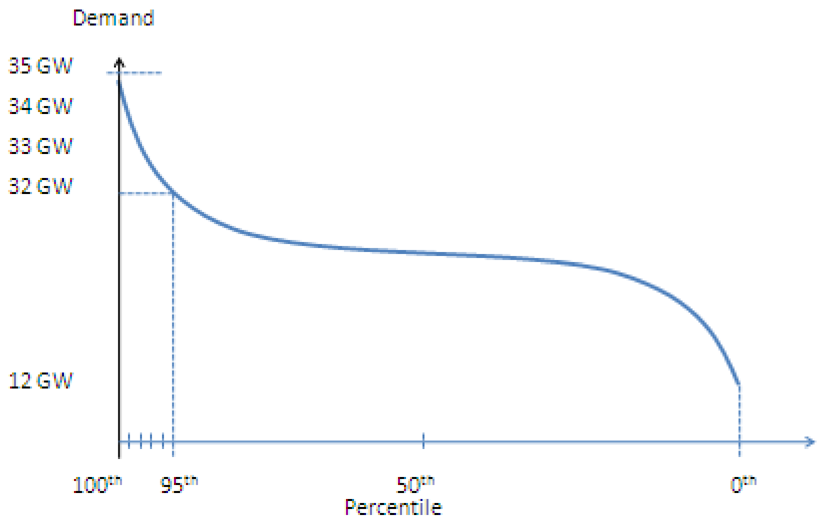

Figure 9 Load duration curve

Figure 10 shows the nose curve for the system. Each dot corresponds to the steady state solution for the demand shown on the horizontal axis. The vertical axis represents voltage magnitude at the load. The numbers shown by the dots indicate the percentile loading from the load duration curve corresponding to the loading shown on the nose curve. Thus, the dot closest to the nose represents the 100th percentile load at 35 GW, and the dot farthest away from the nose represents the 95th percentile or 32 GW. As the demand increases the voltage drops. Observe that at the 100th percentile, peak demand, the system voltage is above the "low voltage" line. The horizontal distance between an operating point and the point at which the nose curve intersects the "low voltage" line is the voltage security margin. If the voltage security margin was 800 MW, then the system can absorb an additional 800 MW of demand before experiencing problems due to low voltage. The horizontal distance between an operating point and the nose of the curve is the voltage stability margin. Stable operation of the power system is not possible for loadings beyond the tip of the nose. If the distance from an operating point to the nose were 1000 MW, then the system could absorb at most another 1000 MW before becoming unstable. This quantity is the margin to voltage collapse. The voltage collapse point is the point at which an ideal system would become unstable. Practical systems experience serious issues well before reaching the nose, and hence monitoring both the voltage security margin as well as the voltage stability margin are important. Figure 10 shows a similar nose curve corresponding to the same system but after VAR support has been added to the distribution system near the load. Observe that the system voltage at the 100th percentile loading is higher than in the diagram for the case without the additional VAR support. Observe also that the security margin and the voltage stability margin have increased, although by different amounts. (The shape of the nose changes with varying compensation.)

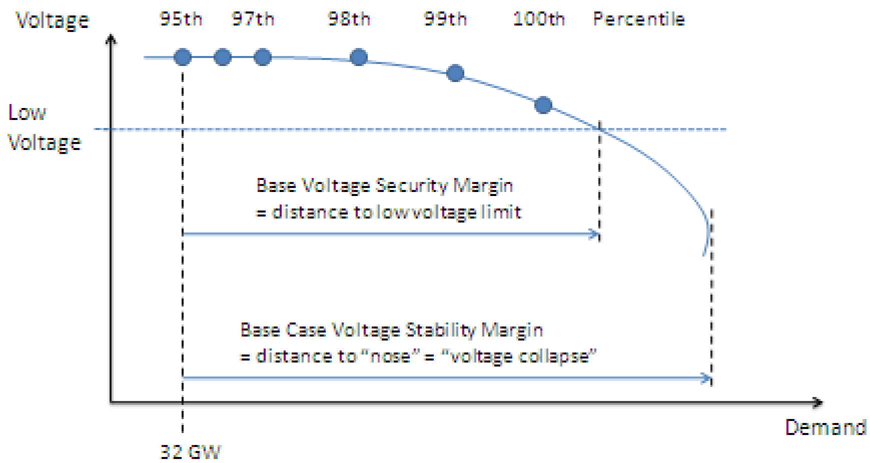

Figure 10 Voltage stability nose curve

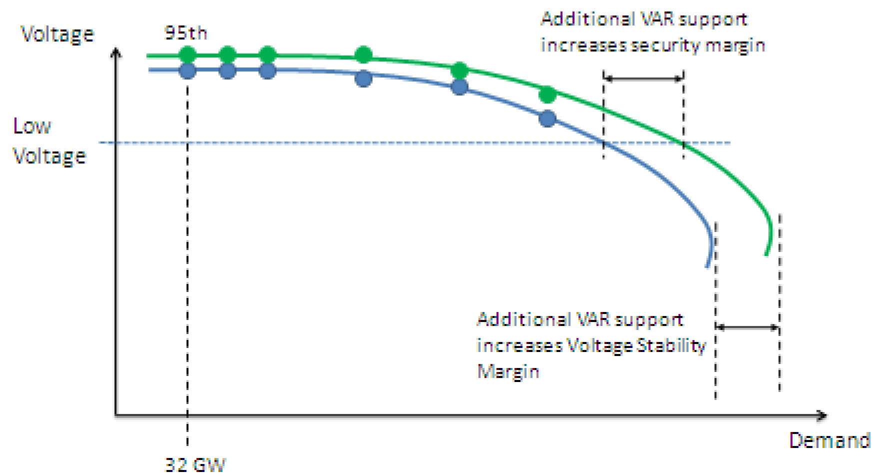

Figure 11 Impact of distribution level VAR support on voltage stability nose curve

Although Figure 11 indicates that the system with added VAR support is farther away from either low voltage or voltage collapse than the unimproved system, from the calculations shown so far both systems are secure at the peak demand. Figure 12 contains the same nose curve as Figure 9, but also shows another nose curve corresponding to a contingency scenario. For instance, the contingency could reflect transmission outages, interchange, or generation outages (for instance, generators providing local VAR support to the load). In this case, the contingency has resulted in a decrease in the security margin and voltage collapse margins. There is some cost associated with operating the system beyond the low voltage limit – local including the potential loss of load. Some contingencies may impact the nose curve so that the 100th percentile loading is below the low voltage limit or beyond the point of voltage collapse. If the nose curve was computed for a comprehensive set of contingencies, and each contingency was associated with a probability, one could estimate the likelihood that a low voltage situation or voltage collapse would be experienced at each load level. The idea is illustrated in Figure 13. If the calculation of the voltage security and voltage stability margins for very many possible operating conditions and contingencies were repeated for both the improved and unimproved cases, the impact of the improvement on the reliability of the system could be measured by the difference in risk distributions. Finally, if the cost of being in a low voltage situation or of sustaining a voltage collapse blackout were postulated, then a dollar amount could be attributed to the difference in reliability. The calculation is illustrated in the appendix.

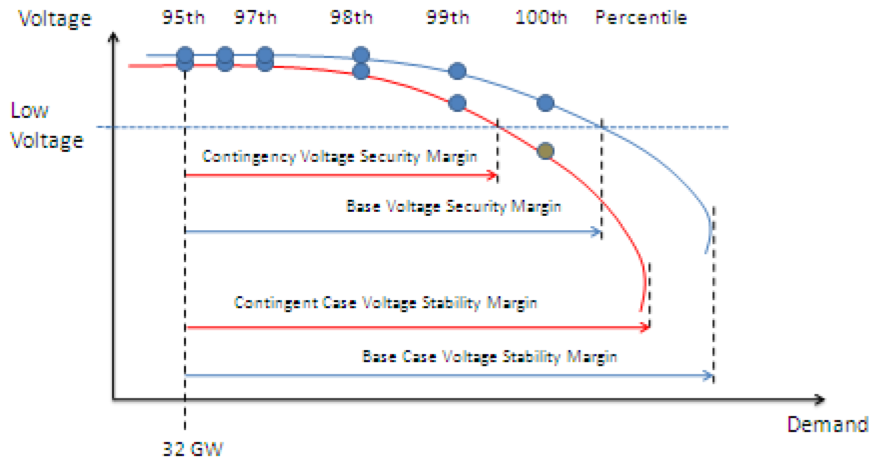

Figure12 Impact of contingency on voltage stability nose curve

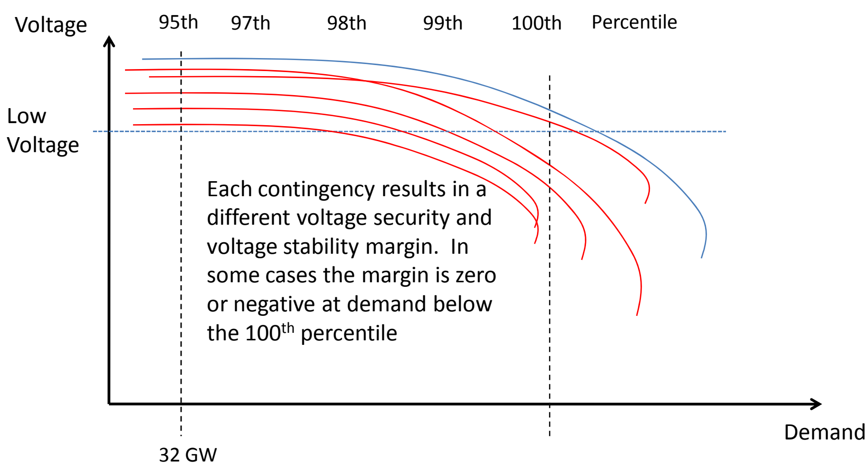

Figure 12 Impacts of contingencies on voltage stability and security

Figure 14 shows the risk duration curve corresponding to both the improved and unimproved cases based on the example in the appendix. The curves are found by computing the expected risk impact for each loading level both with and without the capacitor improvement. The benefit can be measured as the difference between the area under the curves or as the difference in the 99th or 95th percentile, or any other statistical measure used to compare the two distributions.

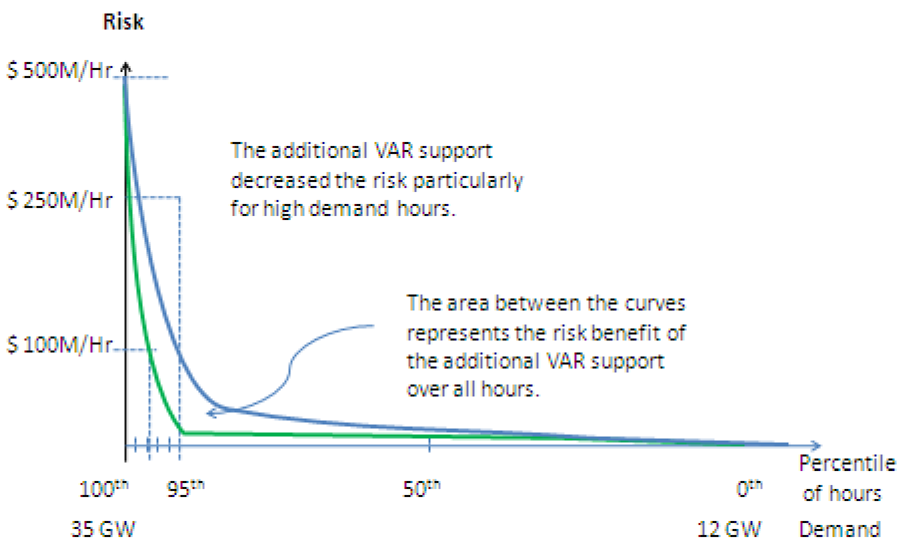

Figure 14 Risk duration curves for pre- and post- added VAR support to system

The steps in the calculation are summarized below and illustrated in the appendix. Note that many variations and embellishments or simplifications to the computations are possible.

1. Establish a forecast load duration curve for the study period. This could come from the historical load duration curve and could be available from the NYSRC Installed Capacity analysis.

2. Establish one or a set of base case load flow solutions.

3. Establish a pattern or patterns of load and transfer increases for the nose curve computation.

4. Establish the universe of contingencies. This could be algorithmic. Probabilities can be associated with line loadings or VAR limits.

5. Compute nose curves and sensitivity to all contingencies. Estimate change in margin for all contingencies.

6. Compute state risk for each load percentile. Assume that there is zero reliability risk for loading below a certain percentile.

7. Compute risk duration curves and conduct risk comparison.

5 Implementation of Capacitor Improvement

5.1 Capacitor Placement Methodology

The objective of the capacitor placement problem is to determine the locations and sizes of the capacitors so that the power loss is minimized and annual savings are maximized. Capacitor optimum placement normally means placing the correct size capacitor banks at locations where they minimize losses. A New York utility has implemented a general philosophy where by you correct the power factor on the distribution system as close to unity power factor as possible by adding capacitors to the distribution feeders to correct the inductive load as close to the load as possible and offset the I^2X component of the substation transformers at the substation. There are two other utilities in NY that target .97 pu power factor for normal and peak load conditions For normal load they utilize fixed capacitor banks to attain the .97 pu power factor and for peak load they utilize switched capacitors to attain the .97 pu power factor[3].

There are many methodologies used to place capacitors on the distribution system. The following are a number of ways:

- Capacitor banks, of any size (600.900.1200kVAR, etc.), should be placed where half their VARs go toward the substation (source) and half away from the source[4]. This rule works for varying feeder wire sizes and for loads that are not evenly distributed.

- Place capacitors until optimum power factor is reached (point where the cost of adding bank exceeds value of losses reduction and equipment utilization benefits). This is usually carried out running multiple load flow studies for fine-tuning the location and size.

- Place capacitors until a predetermined power factor is met.

- Using Optimal Power flow to optimize the capacitor sizes based on preselected locations for installing the capacitors.

- Using Optimal Power Flow to emulate the real-time dispatch and compute the MVAR- LBMP at each location. The MVAR-LBMP is the sensitivity of the as-bid production cost with respect to a lagging MVAR injection at each location. The LBMP is the sensitivity of the as-bid production cost with respect to MW injection at each location. In general, the MVAR-LBMP is about two orders of magnitude smaller than the LBMP. The MVAR-LBMP includes both the impact of each location on losses but also the impact the reduction in flow has on the binding transmission constraints.

- Currently, there are several commercial software packages that utilize genetic algorithm to optimize the capacitor sizes and locations with cost considerations.

Optimal placement would be easy if the load didn't change. The problem with placement studies is that loads change during the day, week, month and most schemes have to deal with all these changes as best they can.

5.2 Capacitor Limitations

Capacitors are intended to be operated at or below their rated voltage. Capacitors shall be capable of continuous operation under contingency system and bank conditions provided that none of the following limitations are exceeded, including harmonic components[5]:

a. 110% of rated rms voltage
b. 120% of rated peak voltage

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[3] New York PSC Case 08-E-0751

[4] Jim Burke, "Considerations When Applying Capacitors on Distribution Systems"

[5] IEEE Std 18-2002, " IEEE Standard for Shunt power Capacitors"

c. 180% of rated rms current
d. 135% of rated reactive power

Despite this attempt to overrate the capacitors for unusual conditions, such as harmonics, many harmonic problems show up first at shunt power capacitor banks, either in the form of blown fuses or capacitor unit failures. The reason for this is that capacitor banks are in many cases part of a resonant loop, resulting in magnification of specific harmonic components. The resulting harmonic voltages and currents are highest at the capacitor bank.

5.3 Capacitor Control Methodology

The distribution line capacitor banks are either switched or fixed. Generally, in determining the type of bank required, the following guidelines should be considered[6] :
a) Fixed capacitor banks are sized for minimum load conditions.
b) Switched capacitor banks are designed for load levels above the minimum condition up to peak load.

The control of a switched capacitor bank is very dependent on things like cost, type of load, climatic conditions, voltage concerns both on the distribution and subtransmission system, amount of acceptable complexity, etc. There are several types of control in use today[7]:

- Voltage
- Current
- VAR
- Temperature
- Time
- Power Factor
- Automation
- Combinations of the above

Some of the advantages and disadvantages of each of these controls is briefly described as follows:

- Voltage is relatively inexpensive and works well when voltage varies with load. On short feeders where voltage drop is not great this method is difficult to coordinate. On modern systems, it is generally used as an over-ride for emergency voltage conditions.

- Current control responds to loading well. It does require a current transformer which adds to the expense. Major problem with current control is that it cannot differentiate between low power factor loads like air conditioners (summer) and high power factor loads (winter) like resistive heating.

- VAR control is effective for minimizing losses and can differentiate between summer and winter peaks. It is expensive since it requires both CT's and PT's. It is very difficult to set VAR controlled capacitors optimally when multiple switched banks are used.

[6] IEEE Std 1036-1992, "IEEE Guide for Application of Shunt Power Capacitors

[7] Jim Burke, "Considerations When Applying Capacitors on Distribution Systems"

- Temperature is simple and inexpensive. It seems to work very well in many areas of the country where air conditioning load dominates peak conditions. One drawback is that it does not recognize holidays or weekends and for this reason usually requires some sort of voltage override.

- Time is also simple and inexpensive. It does not sense abnormal loads and can often get out of sync due to extended power outages, holidays, etc. The more modern voltage controllers avoid most of the concerns associated with the older mechanical units and have had good success in some areas.

- Power Factor is similar in application to VAR control. One consideration with this type of control is a low power level, low power factor load could switch the banks in unnecessarily (the opposite could also be true).

- Automation of capacitor controls is showing very strong promise and customer acceptance since the costs of these schemes is coming down and the benefits, in today's environment can be significant. Some of the benefits of automating the banks are greater flexibility, better VAR support for transmission, control schemes are simpler, and it is easier to detect failed banks.

- Combinations of the above are commonplace especially where voltage is used as an over-ride for emergency conditions.

5.4 Capacitor Grounding and Protection

A. Effect of Grounding

There are a number of ways to ground capacitor banks. While grounded Y banks are normally used, there are sometimes reasons why this connection may not be optimum. A summary of considerations in this area is as follows:

- A three phase capacitor may be connected in Δ, Y-ungrounded or Y-grounded.

- Delta or ungrounded Y offers the greatest possibility of neutral inversion or a resonant condition when one or two conductors on the source side of the bank are open. It can consequently be a problem to locate these banks on the load side of a switch or fuse.

- Grounded Y banks are usually used on 4 wire multi-grounded systems only. A grounded Y-bank on an ungrounded system creates a ground source that may interfere with sensitive relaying as well as contribute to overvoltages during ground faults on these ungrounded systems.

- Grounded Y-banks are generally easy to clear since there is adequate ground current. On the other hand, ungrounded banks have the currents limited to 300 percent of normal phase current by the impedance of the other two legs. The fuse must have a continuous current rating of 135% of rated current of the bank and clear in 5 minutes for reasonable coordination. It is sometimes difficult to satisfy both conditions.

B. Protection

The protection of substation capacitor banks includes the following components:

1) Individual capacitor unit fusing
2) Unbalance relaying
3) Overcurrent relaying
4) Surge arresters
5) Phase voltage relays
6) Periodic visual inspections

When a capacitor bank fails, the energy stored in its series group of capacitors is available to dump into the combination of the failed capacitor and fuse. The failed capacitor and fuse must be able to absorb or hold off this energy with a low probability of case rupture of the capacitor unit. The available energy is about 3.19 joules per kVAR. The available energy is compared with the rating of the fuse and capacitor unit. This is one of criteria for selecting a current limiting fuse for high energy applications (large banks) as opposed to an expulsion fuse.
Several capacitor elements may fail before the fuse removes the entire unit, the Unbalance protection relay trip the bank when the condition is excessive. Most Unbalance Protection Schemes operated on the principle that a neutral shift in voltage occurs when elements in one phase fail.

6 References

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9. S. Greene, I. Dobson, F. L. Alvarado, .Contingency Analysis for Voltage Collapse via Sensitivities from a Single Nose Curve., IEEE Trans. Power Systems, vol. 14, no. 1, Feb. 1999 pp. 232-240

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Appendix 1

This appendix illustrates numerically the computation of the risk benefit. For this example, assume that for violation of the low voltage limit, the reliability cost is equal to $10,000/MW of demand that would be curtailed to move back to a secure voltage. Assume that for a voltage collapse, the cost is $500 million dollars. For the unimproved case, comprehensive contingency analysis has identified only three contingencies associated with a violation of the low voltage limit for loading below the 100th percentile. Table A-1 shows the base case and contingencies for each loading percentile corresponding to the unimproved case and Table A-2 for the case in which VAR support was added to the distribution system. The quantity in parenthesis indicates the negative margin experienced at the corresponding percentile loading. Thus, for contingency B and a demand of 34 GW, the system is 1010 MW beyond the low voltage limit, meaning that 1010 MW would need to be shed to restore the system voltage back to acceptable limits.

Contingency & Probability	98th percentile 33000 MW	99th percentile 34000 MW	100th percentile 35000 MW
A (0.0001)	Secure	Low Voltage(500MW)	Voltage Collapse
B (0.0001)	Low Voltage(10MW)	Low Voltage(1010MW)	Low Voltage(2010MW)
C (0.0001)	Secure	Low Voltage (100MW)	Low Voltage (1100MW)
Base Case and all other contingencies (0.9997)	Secure	Secure	Secure

Table A-1 Base case impacts of contingencies on voltage stability and security

Contingency & Probability	98th percentile 33000 MW	99th percentile 34000 MW	100th percentile 35000 MW
A (0.0001)	Secure	Secure	Low Voltage (900MW)
B (0.0001)	Secure	Secure	Low Voltage(800MW)
C (0.0001)	Secure	Secure	Low Voltage (100MW)
All other (0.9997)	Secure	Secure	Secure

Table A-2 Post-VAR improvement impacts of contingencies on voltage stability and security

Table A-3 shows the unimproved costs associated with each state and load percentile by applying $10,000/MW for low voltage and $500 million for a voltage collapse while Table A-4 contains the same information for the improved case.

Contingency & Probability	98th percentile 33000 MW	99th percentile 34000 MW	100th percentile 35000 MW
A (0.001)	0	$5,000,000	$500,000,000
B (0.001)	$100,000	$10,100,000	$20,100,000
C (0.001)	0	$1,000,000	$11,000,000
Base Case and all other contingencies (0.997)	0	0	0
Risk – expected reliability cost	$100	$16,100	$531,100

Table A-3 Base case risk impacts (expected $ per hour) of contingencies on voltage stability and security

Contingency & Probability	98th percentile 33000 MW	99th percentile 34000 MW	100th percentile 35000 MW
A (0.001)	0	0	$9,000,000
B (0.001)	0	0	$8,000,000
C (0.001)	0	0	$1,000,000
Base Case and all other contingencies (0.997)	0	0	0
Risk – expected reliability cost	0	0	$18,000

Table A-4 Post-VAR improvement risk impacts (expected $ per hour) of contingencies on voltage stability and security

Appendix 2 - Basic modeling information

Consider the system shown in Figure A-5 below. The active and reactive power received at the load end can be represented as:

$$P = \frac{EV}{X}\sin\delta$$

$$Q = \frac{EV}{X}\cos\delta - \frac{V^2}{X}$$

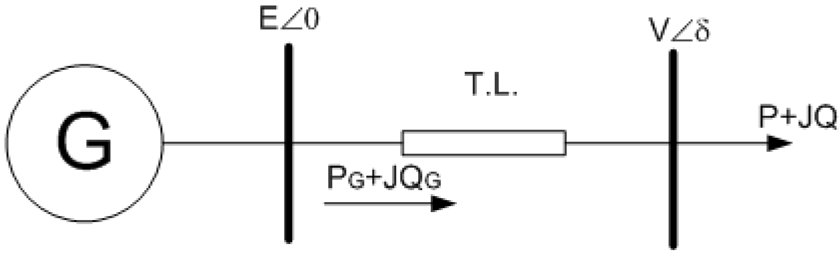

Figure A-5 System Single line diagram

By eliminating δ and solving V^2 for we get:

$$V^2 = \frac{E^2}{2} - QX \pm \sqrt{\frac{E^4}{4X^2} - P^2 - Q\frac{E^2}{X}}$$

The equation has real positive solutions if:

$$P^2 + Q\frac{E^2}{X} \le \frac{E^4}{4X^2}$$

Using $S_{sc} = \frac{E^2}{X}$, the short circuit apparent power and substitute we get

$$P^2 + QS_{sc} \le (\frac{S_{sc}}{2})^2$$

For P=0 the maximum reactive power that can be transmitted to the load is $Q_{\max} = \frac{S_{sc}}{4}$

For Q=0 the maximum real power that can be transmitted to the load is $P_{\max} = \frac{S_{sc}}{2}$

Figure A-6 shows the relation between load voltage and load power for different reactive loadings.

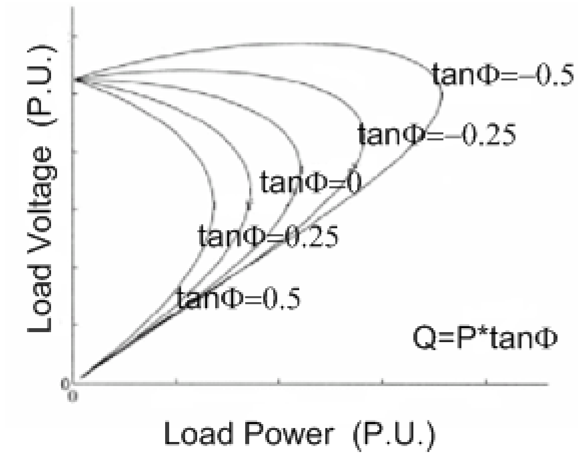

Figure A-6 shows the dependency of receiving end voltage to load power for a Transmission line (the P-V curve)