8. Distribution Voltage Deviation and RE Design

The author started to study the theme recently. Many engineers have already studied the theme. The author had better to concentrate energy in stability problems. However, reading research reports about the theme, queer remarks exist. Therefore, the author also started the study and unique knowledges are obtained. They are introduced in the chapter.

The first queer remark is to introduce “two way communication” as countermeasure of voltage deviation due to RE. The technique is now developing. It seems too aggressive to discuss RE high penetration based on developing technique, although developing technique can be insurance. New business accompanying new technology may be attractive and it may be motive of the aggressive tendency. At first it should be checked whether problems are able to be solved by only now available measures. If not, a new technology is needed. As introduced later, three technologies are available now, that is, tap control on distribution transformer, SVR (Step Voltage Regulator) that is tap changer at midst of distribution line, and constant leading power factor operation on RE.

The second queer remark is to employ SVC (Static Var Compensator) for mitigating voltage deviation on distribution network as if it is a common sense. However, SVC is expensive equipment. Although SVC has splendid performance, the other more economical measures must be considered. As an example, today’s photovoltaic generator (PV) employs IGBT (Insulated Gate Bipolar Transistor) in interconnection inverter. Because, using high frequency switching, harmonics are suppressed. More important merit is that it can control positive and negative active and reactive power independently. In other words, IGBT based inverter includes SVC function. If so, why they do not use it but adopt SVC?

The third queer remark is to operate SVC and RE as constant voltage. If constant voltage equipments are connected in distribution system whose resistance is larger and reactance is smaller than transmission system, much cross current may be caused by such as reference voltage error and so on. In natural inflow hydro power station, multiple turbines are equipped and number of operating turbine is changed by water flow. Multiple generators are usually connected to same bus. Therefore, anti cross current function is adopted in excitation system of generator. Do speakers know cross current? Measuring error of voltage sensor is also troublesome. If voltage must be kept in 101 to 107V and sensors have 2% error, permissible control band becomes to 101+2.4 to 107 – 2.4V, that is, 103.4 to 104.6V. Permissible band width is only 104.6 – 103.4 = 1.2V. Is Such a control realistic?

Tap Control on Distribution Transformer

The most effective measure for distribution network voltage regulation is it. And it is very economical. But it has two defects. One is smooth control is impossible, because tap control is discrete. For the defect, tap notch is selected small, and is usually 1 to 2 %. Another is that some time delay accompanies to tap change. Therefore, good following to sudden large voltage change is impossible. In the past, the delay did not cause problem. However, if RE highly penetrates, phenomena causing sudden voltage change problem will be introduced such as parallel-in of large wind generator, output fluctuation of large PV, and so on. The problem is considered later.

[Scheduling] In tap control, controllable measure is only tap. And only three measured quantities; time t, voltage vector $\mathbf{V}$ at substation bus, and load current vector $\mathbf{I}$ at substation bus are available for control. The most primitive control use time t and amplitude of voltage vector $|\mathbf{V}|$, and tap is controlled so that voltage $|\mathbf{V}|$ follows scheduled value in advance. The control method is called as "scheduling" or "program control".

[Vector LDC] LDC (Line Voltage Drop Compensation), uses all the three quantities; time t, voltage vector $\mathbf{V}$, and current vector $\mathbf{I}$ for presuming load voltage and tap is controlled so that load voltage follows scheduled value in advance. This is one step advanced method than scheduling, but has long and successful history.

In analogue era as shown in Fig. 8.1, LDC made a reduced replica of distribution network at low voltage secondary circuit of potential transformer PT and current transformer CT as and synthesized load voltage vector $\mathbf{V_{L2}}$ by vector calculation $\mathbf{V_{L2}} = \mathbf{V_2} - \mathbf{Z_2}\,\mathbf{I_2}$. Since the LDC employs replica, calculation error never occurs so long as LDC impedance $\mathbf{Z_2}$ correctly expresses real network. Even if reverse power flow occurred by highly penetrated RE, the LDC recognizes load voltage as high and makes tap position lower. Therefore, voltage regulation function is kept sound. Of course designer in those days did not predict the high RE penetration. But their faithful voltage calculation design resulted effective method for today's condition.

When digital era came, utility employing the author realized the same protocol on digital equipment faithfully, and merit being operational as "vector LDC" even in reverse flow is inherited.

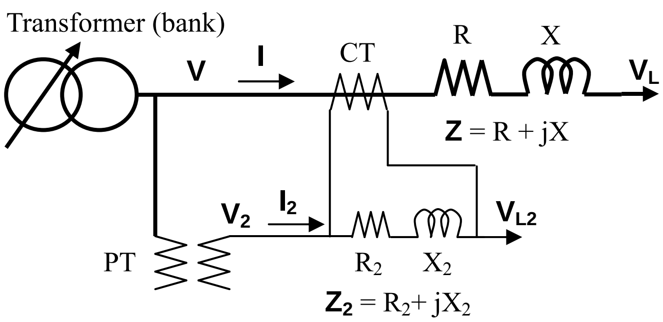

Fig. 8.1 Structure of LDC in analogue era

[Scalar LDC] Recently the author noticed that another type LDC exists. He felt some inconsistency in words of engineers in some Japan-wide congresses, and the inconsistency will be solved if another "scalar LDC" is supposed. By hearing investigation, the deduction was verified as true. The LDC calculates load voltage approximately by scalar calculation $|\mathbf{V_{L2}}| \fallingdotseq |\mathbf{V_2}| - K\,|\mathbf{I_2}|$. Here, K is a positive real number. As the result, load voltage $|\mathbf{V_{L2}}|$ necessarily calculated as lower than substation voltage $|\mathbf{V_2}|$. In reverse power flow condition, real load voltage becomes higher than substation voltage. However, the LDC wrongly recognizes that load voltage is lower than substation voltage, and wrongly makes tap position higher. The type must be called as "scalar LDC", which increases risk of voltage deviation.

At January 2013, Japanese RE Integration Standard prohibits reverse power flow in distribution bank (transformer), and refer problem on voltage regulation as the second reason. Many engineers refer negative effect of scalar LDC due to bank reverse flow as the problem on voltage regulation. However recently, demand to repeal the reverse flow prohibition became stronger. Considering compatibility, perhaps it cannot be avoided to prohibit reverse flow for the present. However by adopting vector LDC as standard from now, the prohibition will be successfully repealed in near future.

LDC Setting

It is necessary to set impedance from substation (s/s) to aggregated load $\mathbf{Z}$ and reference voltage of the aggregated load Vref for LDC operation. There must be certain favorable relationships between the impedance and the reference voltage. If the favorable relationships are not satisfied, LDC will not be able to show sufficient performance.

Favorable LDC setting must vary by load distribution condition. Here, "flat distribution" and "fan form distribution" are assumed as load distribution.

As to the LDC three types of setting methods, "load center method", "voltage center method", and "equivalent loss method" are introduced and examined. "Load center method" employs impedance from s/s to load center as the setting value $\mathbf{Z}$. "Voltage center method" employs the impedance after which voltage drop is equal to half of voltage drop at the tail end of the feeder as the setting value $\mathbf{Z}$. "Equivalent loss method" employs the impedance whose active and reactive losses having aggregated load at its end is equal to losses of the original detailed network.

Hereafter, all variables are normalized by per unit method, except voltage drop, which is normalized as 1 when all loads are concentrated to the tail end of the feeder.

[Flat Distribution Load] In case of "flat distribution load", load amount in every small division along with a feeder is constant. The concept is shown in Fig. 8.2. For an example, loads distribute along with a main street. Or for another example, loads distribute in a narrow field between mountains and sea.

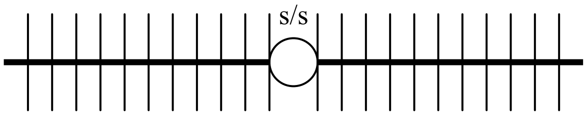

Fig. 8.2 Concept of flat distribution load

Distance from substation (s/s) to the point in question is here expressed as x. Load current density of small division around x is expressed as follows.

$$\Delta I(x) = 1$$

Therefore, feeder current at point x is calculated as follows.

$$I(x) = \int_{x=x}^{1} \Delta I(x)\, dx = 1 - x$$

Voltage drop at point x is calculated as negative value as follows.

$$\Delta V(x) = \int_{x=0}^{x} - I(x)\, dx = \frac{x^2}{2} - x$$

Feeder loss from s/s to tail end of the feeder is calculated as follows.

$$L(x) = \int_{x=0}^{x} I(x)^2\, dx = \frac{x^3}{3} - x^2 + x$$

Calculated distribution current, voltage drop, and loss along with the feeder are shown in Fig. 8.3, in which set impedances (that are normalized as distance from s/s) of the three setting methods are also shown.

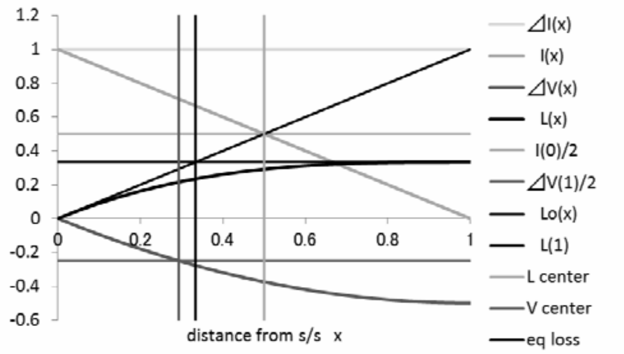

Fig. 8.3 Distribution of current, voltage drop, and loss (flat)

In case of "center load method", load center: $I(x) = 0.5$ is realized at $x = 0.5$. Therefore, half of feeder impedance should be employed as impedance setting **Z**. Voltage drop at $x = 0.5$ is $\Delta V(0.5) = -0.375$. While, voltage drop at the tail end is $\Delta V(1) = -0.5$. Therefore in reference voltage setting, voltage drop at the load center must be regarded as – 0.375 / – 0.5 = 0.75 of voltage drop at the tail end. It must be noticed that voltage drop at load center is unexpectedly large. If voltage drop at load center is wrongly regarded as half of that at the tail end, set reference voltage becomes higher than favorable value, and as the result, distribution network voltage becomes higher than favorable value everywhere.

In case of "voltage center method", set impedance is given as solution of the equation as follows.

$$\Delta V(x) = \frac{X^2}{2} - x = \frac{\Delta V(1)}{2} = \frac{-1}{4}$$

Meaningful solution is obtained as follows.

$$x = \frac{4 - \sqrt{8}}{4} \fallingdotseq 0.292893$$

Voltage drop at point x is, of course, half of that at the tail end. It must be noticed that impedance giving half voltage drop is unexpectedly small as around 29% of whole feeder. If impedance is wrongly set as 50% of whole feeder, distribution network voltage becomes higher than favorable value everywhere.

In case of "equivalent loss method", loss of original distribution network is represented by aggregated load behind 1/3 of whole feeder impedance. Therefore, LDC impedance is set as $x = 1/3$. Voltage drop at $x = 1/3$ is calculated as follows.

$$\Delta V(1/3) = \frac{1}{18} - \frac{1}{3} = \frac{-5}{18} \fallingdotseq 0.277778$$

The value is (– 5/18) / (– 1/2) = 5/9 ≒ 0.555556 of voltage drop at the tail end: $\Delta V(1) = -1/2$. "Equivalent load method" does not set so large impedance as "load center method", and does not set so small impedance as "voltage center method", and a kind of intermediate method.

[Fan Form Distribution Load] When some feeders exist radially from s/s, the concept will be expressed as Fig. 8.4, as if a round pizza is cut radially into some pieces. In the case, load current density of small division around x is proportional to distance from s/s expressed as follows.

$$\Delta I(x) = 2x$$

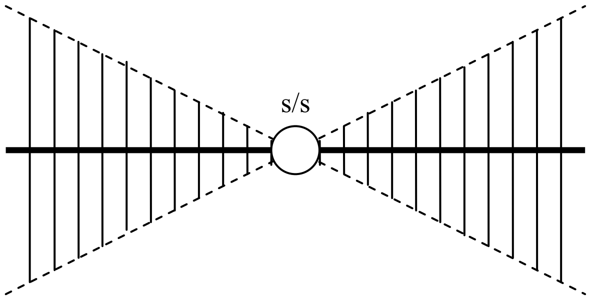

Fig. 8.4 Concept of fan form distribution load

Therefore, feeder current at point x is calculated as follows.

$$I(x) = \int_{x=x}^{1} \Delta I(x)\,dx = 1 - x^2$$

Voltage drop at point x is calculated as negative value as follows.

$$\Delta V(x) = \int_{x=0}^{x} -I(x)\,dx = \frac{x^3}{3} - x$$

Feeder loss from s/s to tail end of the feeder is calculated as follows.

$$L(x) = \int_{x=0}^{x} I(x)^2\,dx = \frac{x^5}{5} - \frac{2x^3}{3} + x$$

Calculated distribution current, voltage drop, and loss along with the feeder are shown in Fig. 8.5, in which set impedances (that are normalized as distance from s/s) of the three setting methods are also shown.

Fig.8.5 Distribution of current, voltage drop, and loss (fan)

In case of “load center method”, load center: $I(x) = 0.5$ is realized at $x = 1/\sqrt{2}$. Therefore, 71% of feeder impedance should be employed as impedance setting **Z**. Voltage drop at $x = 1/\sqrt{2}$ is $\Delta V(1/\sqrt{2}) = -0.457107$. While, voltage drop at the tail end is $\Delta V(1) = -2/3$. Therefore in reference voltage setting, voltage drop at the load center must be regarded as $-0.457107 / (-2/3) = 0.685669$ of voltage drop at the tail end.

In case of “voltage center method”, set impedance is given as solution of the equation as follows.

$$\Delta V(x) = \frac{x^3}{3} - x = \frac{\Delta V(1)^2}{2} = \frac{-1}{3}$$

Meaningful solution is obtained as $x \fallingdotseq 0.347296$ as impedance setting. Voltage drop at point x is, of course, half of that at the tail end.

In case of “equivalent loss method”, loss of original distribution network is represented by aggregated load behind $L(1)$ = 8/15 of whole feeder impedance. Therefore, LDC impedance is set as x = 8/15. Voltage drop at x = 8/15 is calculated as $\Delta V(8/15) \fallingdotseq -0.391111$, which is − 0.391111 / (– 2/3) = 5/9 ≒ 0.586667 of voltage drop at the tail end: $\Delta V(1)$ = – 2/3. Also in case of fan form distribution load, “equivalent load method” does not set so large impedance as “load center method”, and does not set so small impedance as “voltage center method”, and a kind of intermediate method.

Reverse Flow Limit in Distribution Transformer due to Pole Trans Tap Variation

Vector LDC is superior, because it enables reverse power flow in distribution transformer. Then, are all problems around reverse power flow solved by vector LDC? Regretfully, the answer is The author is “no”. A serious cause is pole trans tap variation. Standard tap is 6600V/105V in Japan. In addition, 6750V/105V and 6450V/105V taps are used. In forward power flow, it is favorable to keep substation voltage high. To avoid over voltage at the secondary of pole transformer, 6750V/105V tap is sometimes adopted near substation. At the end of feeders, voltage will decline. Therefore, 6450V/105V tap is sometimes adopted at the end of feeders to keep pole transformer secondary voltage at sufficient level.

Thus, pole transformer tap variation performs an important role in distribution voltage regulation. However, the performance is limited only in forward power flow. In reverse power flow, pole transformer tap variation will show a negative effect.

Permitted voltage in MV (6600V in Japan) is assumed to be 101 to 107V at the secondary of no load pole transformer connecting to the MV network point at in question. Permitted MV voltage ranges in the four pole trans tap variation cases are calculated both in forward and reverse power flow as follows. 高圧

(1tap)　All pole transformers have 6600V/105V tap. Permitted MV ranges are calculated as follows. The range is equal in forward and reverse power flow.

Forward:　s/s:　107V (6600V/105V) = 6726V,　end:　101V (6600V/105V) = 6349V

Reverse:　s/s:　101V (6600V/105V) = 6349V,　end:　107V (6600V/105V) = 6726V

(2tapA)　Most pole transformers have 6600V/105V tap, and 6450V/105V tap is adopted near the end of feeders. Permitted MV ranges are calculated as follows. The range becomes wider in forward power flow, but becomes narrower in reverse power flow.

Forward:　s/s:　107V (6600V/105V) = 6726V,　end:　101V (6450V/105V) = 6204V

Reverse:　s/s:　101V (6600V/105V) = 6349V,　end:　107V (6450V/105V) = 6573V

(2tapB)　Most pole transformers have 6600/105V tap, and 6750V/105V tap is adopted near substation. Permitted MV ranges are calculated as follows. The range becomes wider in forward power flow, but becomes narrower in reverse power flow.

Forward:　s/s:　107V (6750V/105V) = 6879V,　end:　101V (6600V/105V) = 6349V

Reverse:　s/s:　101V (6750V/105V) = 6493V,　end:　107V×(6600V/105V)＝6725V

(3tap)　Most pole transformers have 6600/105V tap, 6750V/105V tap is adopted near substation, and 6450V/105V tap is adopted near the end of feeders. Permitted MV ranges are calculated as follows. The range becomes significantly wider in forward power flow, but becomes significantly narrower in reverse power flow.

Forward:　s/s:　107V (6750V/105V) = 6879V,　end:　101V×(6450V/105V)＝6204V

Reverse:　s/s:　101V (6750V/105V) = 6493V,　end:　107V×(6450V/105V)＝6573V

Load is assumed to distribute evenly along with main routes of feeders. Voltage change from substation $\Delta V(x)$ at relative distance x $(0<x<1)$ from substation can be calculated as follows. It must be noticed that voltage change is normalized by regarding voltage change at the end as 1 when all loads are aggregated at the end.

$$\Delta V(x) = -x + \frac{x^2}{2}$$

Thus profiles of voltage change $\Delta V(x)$ by relative distance x can be calculated in the four pole transformer tap variation cases. The results are shown in Fig. 8.6.

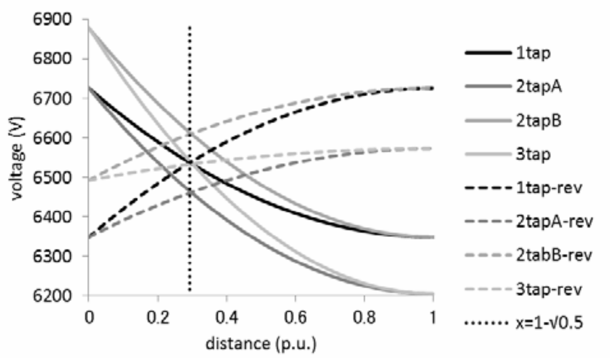

Fig. 8.6 Tap variation and voltage profile

In the figure, it must be noticed that relative distances x_c where profile curves of forward and reverse power flow crosses are almost equal in the four pole transformer tap variation cases. (Slight differences exist, but they are very small.) The relative distance x_c is accurately calculated in 1 tap case as follows.

$$1 - \sqrt{0.5} = 0.292893$$

Product of the factor above and distribution network impedance Z is suitable for LDC impedance setting. MV voltage at x_c is equal to average of s/s and end voltages. The voltage is suitable for LDC voltage setting.

The LDC setting method is same of the "voltage center method" already introduced. However in existing distribution networks, it is difficult to identify the impedance Z. As a solution, Z/3 can be identified by the "equivalent loss method". Thus Z is already known, and $(1 - \sqrt{0.5})\ Z$ can be calculated as "voltage center method" LDC impedance setting.

The LDC setting enables to use full MV permitted range in both forward and reverse power flow, and therefore, it also enables to realize maximum both forward and reverse power flow. The LDC setting will be quite useful in near future when reverse power flow is very often seen due to highly penetrated PV generation.

The maximum power flow Pmax can be calculated as follows. Here, Vss is voltage at substation, and

V_{end} is voltage at the end. Coefficient 2 is introduced, because $\Delta V(x)$ shows value – 1/2 at x = 1.

$$P_{max} = 2\ (V_{ss} - V_{end})$$

Thus, maximum power flows by pole transformer tap variations can be calculated. The results are shown in Fig. 8.7 normalized maximum power flow (both forward and reverse) in 1tap case as 1. Wider tap band results larger permitted maximum power flow in forward power flow, but on the contrary in reverse power flow case results smaller permitted maximum power flow, which is only 0.21 in 3tap case.

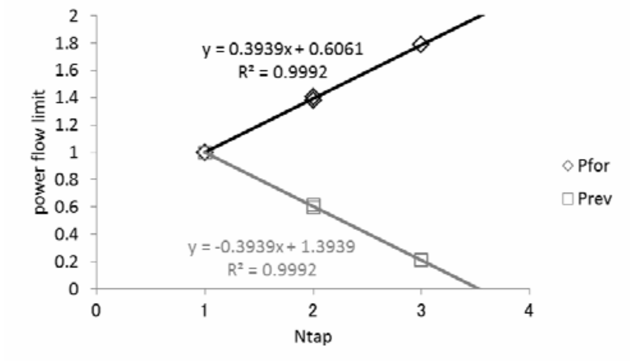

Fig. 8.7 Maximum power flow and tap variation

To enlarge permitted reverse power flow, SVR that has variable tap becomes indispensable instead of fixed pole transformer variation. However, changing many pole transformers' tap is a laborious and costly (because of preparing power source car for avoiding even planed outage) task, which will be inconvenient.

SVR (Step Voltage Regulator)

SVR (Step Voltage Regulator) is an autotransformer equipped on distribution line, and regulates secondary voltage by tap control. Typically, upside 4 taps and downside 3taps are equipped by 100V notch around 6600V. SVR also has long and successful history.

In voltage regulation by SVR, it is important to distinguish system center side and ending side. When tap is changed, system center side of SVR voltage hardly changes, but that of ending side changes. Distribution network very often takes temporary structure. System center side and ending side of SVR may become reverse temporarily. If REs do not exist, the temporary reverse direction can be detected by reverse power flow, and direction was automatically changed. However if REs much penetrate, it is not distinguished whether the reverse power flow is generated by temporary structure of distribution network or much output power of REs. For the solution various methods are now on developing. Difference of both side impedances seen from SVR is regarded as hopeful in present, but by what occasion the impedances are measured is in question. A primitive method that operators set direction by telecontrol may be also considerable, so the author thinks.

PV's Constant Leading Power Factor Operation [1]

There are two types of measures for distribution voltage regulation also effective in case of high RE penetration. Two measures introduced above are measures at power system side. Here, a method at PV side is introduced.

[Leading and Lagging Power Factor] Before entering to main stream of the theme, what "leading power factor" and "lagging power factor" are must be restudied. Japanese RE Integration Standard very often adopts such expression as "leading power factor seen from power system side". However, leading and lagging power factor never changes by seeing direction. If writers do not understand power factor correctly, correct remark hereafter must be useful.

Any texts of electric engineering introduce voltage vector diagram of sending and receiving end as shown in Fig. 8.8. In the figure at receiving end, phase angle of current vector **I** is lagging ϕ from that of voltage vector $\mathbf{V_R}$. Reactive power in the situation is called as "lagging reactive power" and power factor in the situation is called as "lagging power factor, because current vector phase angle is lagging from that of voltage vector.

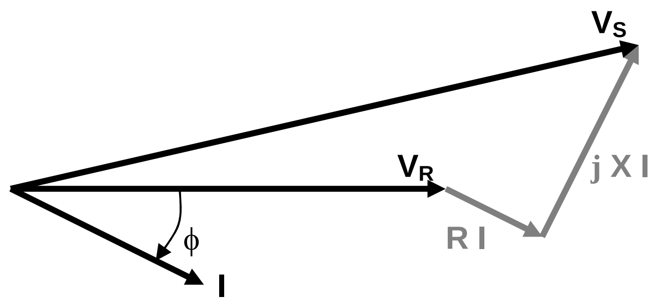

Fig. 8.8 Voltage vector at sending and receiving end

In electric power circuit, complex power whose real part means active power and imaginary part means reactive power is used. In electric power circuit, the complex power is defined power by product of voltage vector **V** and conjugate current vector $\mathbf{I}^*$. Taking voltage vector phase as base, current vector is expressed as $\mathbf{I} = I\,(\cos(-\phi) + j\sin(-\phi))$. Therefore, complex power is calculated as follows.

$$P + j\,Q = \mathbf{V}\,\mathbf{I}^* = V\,I\,(\cos(-\phi) + j\sin(-\phi))^* = V\,I\,(\cos(-\phi) - j\sin(-\phi))$$
$$= V\,I\cos\phi + j\,VI\sin\phi$$

Thus, $P = V\,I\cos\phi$ and $Q = V\,I\sin\phi$ are conducted. P and Q is positive real number. Therefore, lagging reactive power is expressed as positive in electric power circuit, and the route is that complex power was defined as $\mathbf{V}\,\mathbf{I}^*$. If phase angle of current vector is leading from that of voltage vector, reactive power Q turns to negative. It can be recognized that lagging power factor means $Q/P > 0$, and leading power factor means $Q/P < 0$. If active power P is positive, positive reactive power means lagging power factor, and negative reactive power means leading power factor. Therefore, such expression that leading or lagging power factor "seen from power system side" cannot exist. Further saying, the author does not like expression as "95% leading power factor", but chooses expression as "Q = -0.3P (deserves 95% leading power factor). Perhaps the latter expresses more distinct physical meaning.

[Voltage Drop] In the vector diagram, sending end voltage vector $\mathbf{V_S}$ can be strictly calculated as follows by taking receiving end vector voltage $\mathbf{V_R}$ as base.

$$\mathbf{V_S} = V_R + (R + j\,X)\,I\,(\cos\phi - j\sin\phi) = V_R + (R\,I\cos\phi + X\,I\sin\phi) + j\,(X\,I\cos\phi - R\,I\sin\phi)$$

Since imaginary part of $\mathbf{V_S}$ is small, it can be neglected as follows.

$$V_S \fallingdotseq V_R + R\,I\cos\phi + X\,I\sin\phi$$

Here, active and reactive power at receiving end are $P_R = V_R\ I\ \cos\phi$ and $Q_R = V_R\ I\ \sin\phi$, but approximately expressed as follows, because voltage is almost 1 in normal operation.

$$V_S \fallingdotseq V_R + R\,P_R + X\,Q_R$$

Thus, well known approximated equation of voltage drop is derived as follows.

$$\Delta V = V_S - V_R \fallingdotseq R\,P_R + X\,Q_R$$

By the way, it may be easily noticed that $\Delta V \fallingdotseq 0$ can be realized if $Q_R/P_R = -R/X$ can be realized. That is, leading power factor has a function making voltage drop (rise) smaller. If both RE and load operate in leading power factor, distribution voltage deviation will be significantly mitigated. In Japan, most customers show almost unity power factor, because high power factor is well treated in electric charge. RE can easily employ slight ($Q = -0.2\ P$ or so) leading power factor operation, and distribution voltage deviation will not become so serious problem.

Constant power factor operation has been long and widely adopted in hydro power stations with no problems. No cross current appears like constant voltage control. Hydro power stations adopt constant lagging power factor operation to compensate reactive power loss in transmission line from hydro power to receiving end substation, where compensation capacitor becomes needless. Of course during maximum power generation, voltage at power station will rise. But it is already taken into account. The voltage rise is 5% or so. Therefore in main transformer of hydro power station, generator side tap is set around 5% lower than transmission line side. Since control character of “constant leading power factor” and “constant lagging power factor” are not different, and certainly some hydro power station employs leading power factor, leading power factor operation is counted as a today’s available technology.

Voltage Simulation on a Very Long Distribution Line

Voltage simulation in high RE penetration is tried by using only today’s available measures. Long distribution line (10km) shown in Fig. 8.9 is taken as model.

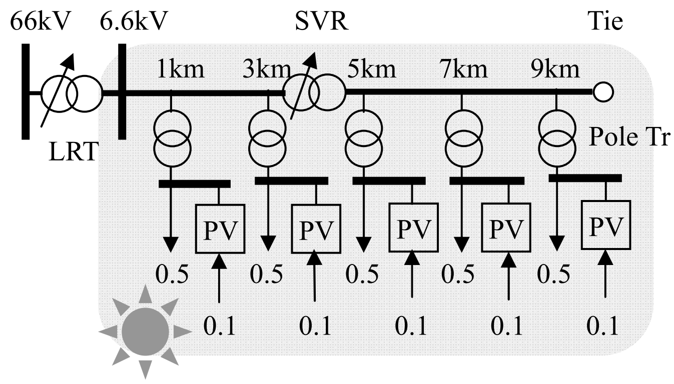

Fig. 8.9 PV output increase in a long feeder

Reactance of 4MVA distribution transformer is considered. The capacity is decided by 20MVA/5feeders. Size of MV line is Cu 80sq. Load is assumed evenly distributed along the feeder. The feeder is divided into five equal series sections. Each section is arrogated to a pole transformer, a load, and a PV. Impedance of pole transformer is 1 + j 3 at its 0.5MVA capacity base. Tap is chosen as 6600V/105V. For compensating voltage drop, a SVR is equipped at 4km point and step voltage up by 2 taps (3.1%). During 10 min to 20 min output of PV increases 0.1MW to 0.5MW. As the result, the feeder becomes almost zero power flow anywhere.

PV power factor is assumed Q = 0 to -0.5P by 0.1P step. LRT tap control is assumed as scheduling, scalar LDC, and vector LDC. Simulation program is CRIEP V-method, which cannot deal with scalar LDC. Therefore, as an approximate expression, X_2 in vector LDC is set as 0. The expression cannot deal with reverse power flow, but can zero flow.

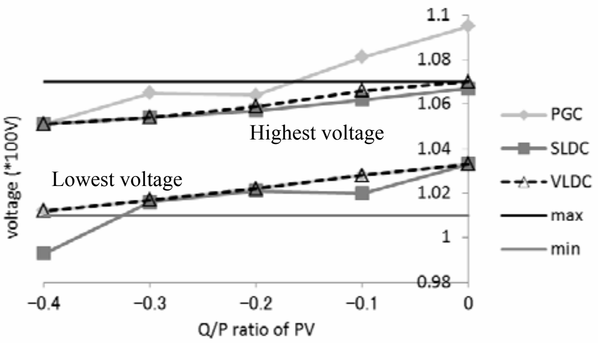

Fig. 8.10 Highest and lowest voltage in simulation

Simulation results are summed in Fig. 8.10 by highest and lowest voltages at pole transformer secondary. In case of scheduling (PGC), highest voltage exceeds 107V (limitation by rule) at Q = 0 and Q = -0.1P. In case of scalar LDC (SLDC), lowest voltage does not reach 101V (favorable least voltage at pole transformer secondary) at Q = -0.4P. In case of vector LDC, all voltages stand within 101 to 107V, and margin is largest at Q = -0.2P. Strong leading power factor such as Q = -0.4P shows inferior result. The results are quite favorable, because a little larger capacity is needed for strong leading power factor. Slight leading power factor Q = -0.2P results 102% current if voltage is 100%. Voltage must rise at least 102% by PV output. Then capacity up in inverter is useless, and small PV generator is not forced uneconomical way.

Tap and voltage in simulation results of typical examples are introduced. In case of scheduling and Q = 0 (Fig. 8.11), LRT tap does not move, because substation voltage does not vary much. SVR wearing vector LDC steps down by 5 taps, and voltages at 5km or further are kept normal. However at 1km and 3km, voltage rise is much and exceed 107V. Considerable part of voltage rise is generated in pole transformer.

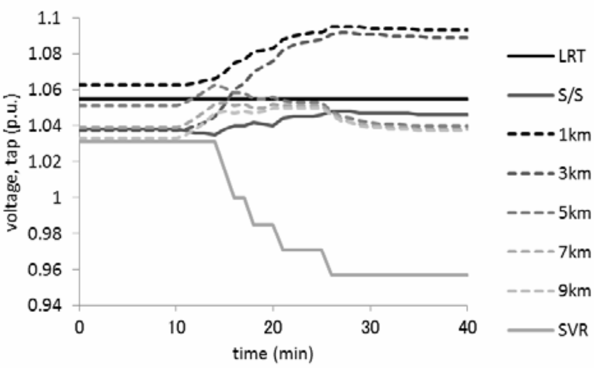

Fig. 8.11 Simulation results (Scheduling, Q = 0)

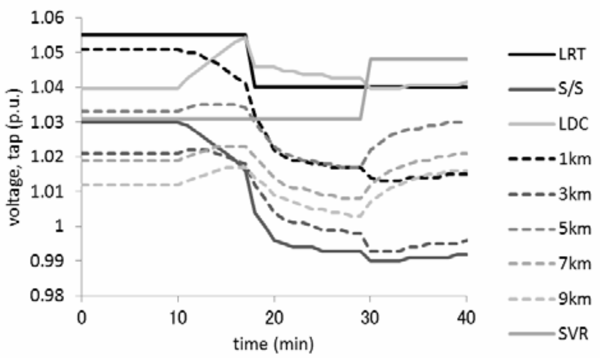

Fig. 8.12 Simulation results (scalar LDC, Q = -0.4P)

In case of scalar LDC and Q = -0.4P (Fig. 8.12), the LDC ignores voltage drop due to absorbed reactive power by PV and network reactance, wrongly presumes load voltage higher, and makes LRT step down by 1 tap. Voltages in front of SVR become lower and voltage at 3km becomes lower than 101V. Voltages behind SVR are kept normal.

In case of vector LDC and Q = -0.2P (Fig. 8.13), LRT and SVR step voltage down by 1 tap respectively, and voltages are kept within favorable band and seems to converge toward around 104V, the most favorable voltage. Although the model feeder stands in rather severe condition, voltage is well regulated by only today's available measures. Therefore, it is understand that to make test calculation how further today's available measures can solve voltage deviation problem.

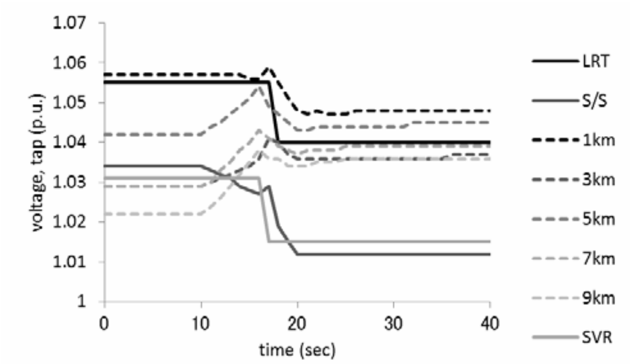

Fig. 8.13 Simulation results (vector LDC, Q = -0.2P)

By the way, it is vector LDC on LRT that most contributes to voltage regulation. However to demonstrate its ability, adequate LDC impedance $\mathbf{Z_2}$ setting is indispensable. Three methods are already introduced. Among them, most promising technique is, perhaps, "equivalent loss method", another name is "Y-conecction aggregation method[3]", which is introduced in chapter 3. Here, it is introduced a little more minutely. By the method, load's weighted average voltage is approximately preserved, if $\mathbf{Z_2}$ is set so that active and reactive power loss in network under the LRT is preserved.

That above mentioned is easily verified. Y-connection method adopts a concept, complex phase angle θ, which is sum product of impedance Z_i and power flow P_i along the path from aggregation bus to each load as follows.

$$\theta = \Sigma\,(Z_i\,P_i)、\qquad Z_i = R_i + j\,X_i$$

Here, Q/P ratio on each path can be regarded as approximately constant, that is, $Q/P = a$. Then, complex phase angle can be expressed as follows, and its weighted average should be preserved through aggregation.

$$\theta = \Sigma\,\{\,(R_i + j\,X_i)\,P_i\,\} = \Sigma\,(R_i\,P_i) + j\,\Sigma\,(X_i\,P_i)$$

Weighted average of real and imaginary parts of θ is preserved respectively. And, imaginary part can be expressed as follows.

$$\Sigma\,(X_i\,P_i) = (1/a)\,\Sigma\,(X_i\,Q_i)$$

Therefore, weighted average of the expression as follows is also preserved through aggregation.

$$\Sigma\,(R_i\,P_i + X_i\,Q_i)$$

The expression above means voltage drop of the path approximately. Thus, weighted average voltage drop is also preserved through Y-connection aggregation. Q.E.D.

Perhaps many Japanese engineers in power distribution section will oppose that in case of even load distribution loss becomes 1/3 and voltage drop becomes 1/2 of receive end concentrated load case. Therefore, voltage drop is not preserved, even if loss is preserved. Therefore for an example, some calculations are shown in case of even load distribution. Sending end is defined as x = 0, and receiving end is defined as x = 1. In even distribution, current at point x is I(x) = 1 – x. Therefore, sum voltage drop from sending end to point x is calculated as follows.

$$\varDelta V(x) = \int_{x=0}^{x} (1 - x)\, dx = x - \frac{x^2}{2}$$

Voltage drop at receiving end is certainly 1/2 of concentrated load at receiving end case. However, weighted average load's voltage drop must be calculated as follows.

$$\varDelta V_{ave} = \int_{x=0}^{1} \left(x - \frac{x^2}{2}\right) dx = \left[\frac{x^2}{2} - \frac{x^3}{6} \right]_{x=0}^{1} = 1/3$$

That is 1/3 of concentrated load at receiving end case. Loss is calculated as follows.

$$P_{loss} = \int_{x=0}^{1} (1 - x)^2\, dx = \left[x - x^2 + \frac{x^3}{3} \right]_{x=0}^{1} = 1/3$$

Thus, there is no inconsistency in preserving loss and preserving voltage drop.

The fact demonstrated here seems to be important, but no texts refer. Perhaps in old days, professor intended to take as training question and omitted in main body. But, he forgot to take it in training question. However, it seems quite queer for the author that professors later do not have any question.

Voltage Simulation in Reverse Power Flow Case

However, such a 10km long distribution line hardly exists. While, how long the average distribution line is? Hokuriku region in Japan has 4300km^2 inhabitable area. In the area, 180 distribution substations exist. Therefore, average distribution substation has 24km^2 feeding area. Regarding the feeding area as square, half of its diagonal length is almost 3.5km, which can be regarded as average distribution line length. However considering the fact that large PV power stations tend to site in rural area where land cost is small, average length should be assumed a little longer for conservative assessment. Therefore, 5km is taken as the standard distribution line length here.

In analyses before, only one distribution line is modeled and distribution transformer is reduced so that its size matches the one line. However in fact, size of transformer is usually around 20MVA, and average bank feeds to five distribution lines having around 4MW peak load respectively. Lines are different each other. The difference will reduce the effect of LDC. Here, the difference is considered in length. Beside the average length (5km) line, shorter lines (4km and 3km) and longer lines (6km and 7km) are modeled. Using the distribution system model, it is examined whether LDC on tap control and leading power factor on PV can sufficiently regulate voltage even if PV penetrates so much as a considerable reverse power flow appears in distribution transformer, and even if line length is different.

Before the analysis and simulation, since the purpose of PV's leading power factor operation seems to have changed, the history is reviewed once here.

[Change in the Purpose of PV's Leading Power Factor Operation] In the beginning stage of PV penetration, voltage rise due to concentrated residential small PV under the same transformer was the typical problem. In such a case, MV voltage can be regarded as constant. Since LV network under pole transformer has considerably large resistance compared to reactance, strong leading power factor such as 85% is needed for PV to maintain PV terminal voltage within regulation. As the result, a control scheme that makes PV to operate in 85% leading power factor when PV terminal voltage exceeds a threshold value was developed. When PV operates at rated output, terminal voltage is 107%, and power factor is 85% lead, PV current is 1/0.85/1.07=1.10, that is, PV must have 110% capacity of rated output, and cost will rise.

As PV penetrates, mitigation of MV voltage rise has been considered as the main purpose of PV's leading power factor operation, rather than voltage rise mitigation under a certain pole transformer. By the already developed control scheme (85% leading with threshold voltage), since only partial PVs whose terminal voltage exceed threshold absorb reactive power, average power factor under the distribution transformer does not become sufficiently leading, and voltage rise mitigation effect was limited in spite of PV cost rise.

Concept must be changed. For example, an idea that all PVs always operate in leading power factor without threshold is possible. "One for all", that is, every PV operates in leading power factor for mitigating voltage rise of the others even if its own voltage stays within regulation. "All for one", that is, the fruits appears as the voltage rise mitigation of PV with the highest voltage. When PV operates at rated output, terminal voltage is 102%, and power factor is 98% lead, PV current is 1/0.98/1.02=1.00, that is, additional PV capacity is not necessary.

There was a criticism that PV's leading power factor operation increases network loss. Certainly network loss increases a little on one hand. However on the other hand, leading power factor results a little lower network voltage. The lower voltage results a little smaller electric power consumption. Because there are no voltage regulation equipments except tap control on distribution transformer and SVR (Step Voltage Regulator), and average load in distribution network shows constant current character. As the total, sending power from substation becomes a little smaller. If the slightly lower voltage never hinders adequate operation of electrical equipments, PV's leading power factor means "saving energy".

Former analyses and simulations not only have not considered reactance and tap control on distribution transformer adequately but also have not verified distribution network model sufficiently. The author already modeled reactance and tap-control on distribution transformer, and confirmed that daily voltage variation by the model represents the measured voltage well. And using the model, he demonstrated that LDC on tap control and PV's leading power factor have sufficient voltage regulation capability even in Japan 53GW penetration revel [(1)]. However, simulation can show what happens, but cannot show why it happens. Here, a theory that can show why it happens is introduced. The theory is verified by simulation. Model used here is no more than a fiction but reflects reality, because data of detailed model cannot be introduced for want a space.

[Distribution System Model] Its structure is shown in Fig. 8.14. 20MVA transformer feeds five lines with 3km, 4km, 5km, 6km, and 7km length. Peak demand of each line is 4MW. Considering diversity 1.05, 20MVA bank matches five lines very well, and real system is really so designed. Bank impedance is j14.4% at its rated capacity (20MVA) base and is j7.2% at 10MVA base. The impedance is designed so high as 275kV class transformers that short circuit current in distribution network never exceed 12.5kA in Japan.

LDC or PGC is adopted as tap control. Each line is equally divided into five sections. Section one standing at substation side does not have loads. The other four sections have evenly scattered loads. MV conductor is OC150sq whose impedance is 3.21 + j7.80 %/km at 10MVA base in section one to three, and is OC80sq whose impedance is 6.00 + j8.22 %/km at 10MVA base in section four and five.

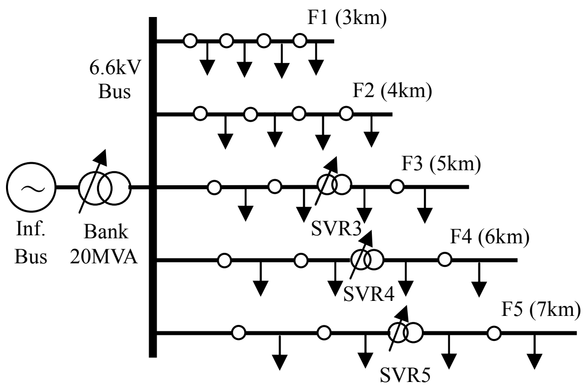

Fig. 8.14 Structure of the studied system

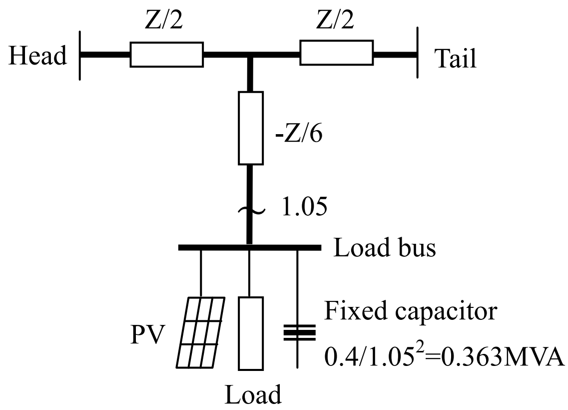

Fig. 8.15 Structure of each section

Structure of each section is shown in Fig. 8.15. When impedance of the section (MV conductor) is Z, evenly scattered load can be aggregated as the figure using “Y-connection method”. As the result, average load voltage and power loss (real and reactive) are preserved through aggregation. Load bus is MV, but for convenience, tap 1.05 is employed so that voltage is expressed as secondary voltage of no-load pole transformer (1 p.u. = 100V). Load is 1MW + j0.3MVar in heavy load period, and is 0.6MW + j0.18MVar in light load period. 0.4MVA fixed MV capacitor is connected. Its capacity is reduced to 0.363MVA considering the tap. PV has 1.1MW rated output. PV increases its output from initial output 0.1MW to 1.1MW during 10 minutes. Since each line has four loads, neglecting loss, power flow of each line varies as follows.

Heavy load period: 3.6MW => -0.4MW

Light load period: 2.0MW => -2.0MW

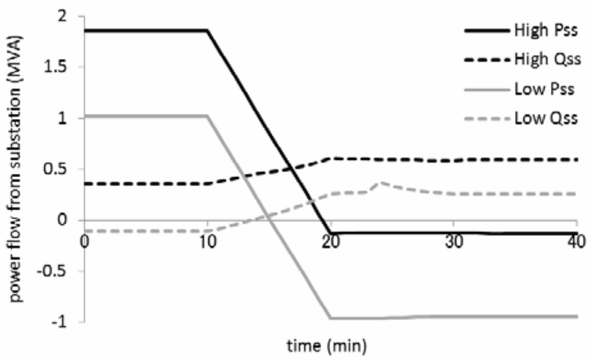

Fig. 8.16 Time variation of substation sending power

Time variation of real and reactive power from substation (heavy load, light load) is calculated as Fig. 8.16. In case of heavy load, power flow magnitude (and loss) much decreases by PV output increase. On the contrary in case of light load, power flow magnitude (and loss) does not vary much before and after PV output increase.

[Approximate Voltage Calculation on Aggregated Model] No change is needed through aggregation in reactance value: X_T = 7.2% (at 10MVA base) and LTC tap position on distribution transformer. On the contrary, distribution network is needed to be far aggregated so that analysis can be done by manual calculation. Using Y-connection method, structure of the aggregated system is shown in Fig. 8.17. Distribution network from substation to load is represented by an impedance: $R_D + jX_D = 1.447 + j3.462$ % (at 10MVA base). In network aggregation, it must be noticed that loads behind SVR should be lumped in front of the SVR. For reality, SVRs are controlled by vector LDC.

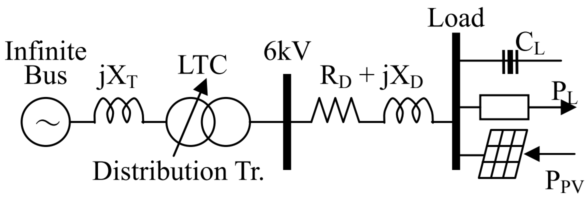

Fig. 8.17 Aggregated model of the distribution system

Voltage change ΔV caused by power output change $\Delta P + j\Delta Q$ in PV on impedance R + jX from a fixed voltage source to PV is approximately calculated as follows.

$$\Delta V = R\,\Delta P + X\,\Delta Q \qquad (1)$$

Therefore, voltage change will be zero if relationship as follows is realized.

$$(\Delta Q/\Delta P)_{opt} = -\,R/X \qquad (2)$$

In constant power factor operation used hereafter, $(Q/P) = -\,R/X$ fulfills the condition above.

In case of LDC, 6kV bus voltage at substation is not regulated, and the fixed voltage source is almost the 77kV bus of substation. Therefore, optimal condition of the example system is calculated as follows.

$$R + jX = 1.447 + j(7.2 + 3.462) = 1.447 + j10.662\ \%$$
$$(Q/P)_{opt} = -\,1.447/10.662 = -\,0.136$$

Even a very light leading power factor such as Q/P = – 0.2 (almost 98% lead) results over compensation, which may be adequate when LV network having larger R/X ratio is considered, but it is another study. LTC tap will not move around the optimal Q/P condition.

In case of PGC, 6kV bus voltage at substation is regulated, and is approximately regarded as fixed voltage source. Therefore, optimal condition of the example system is calculated as follows.

$$R + jX = 1.447 + j3.462\ \%$$
$$(Q/P)_{opt} = -\,1.447/3.462 = -\,0.418$$

It is a considerably strong leading power factor (92%). A little stronger leading power factor such as 85%

(Q/P = – 0.620) seen in former control scheme will be adequate when LV network having larger R/X ratio is considered. However, LTC tap will move for maintaining 6kV bus voltage against large reactive power change by PV.

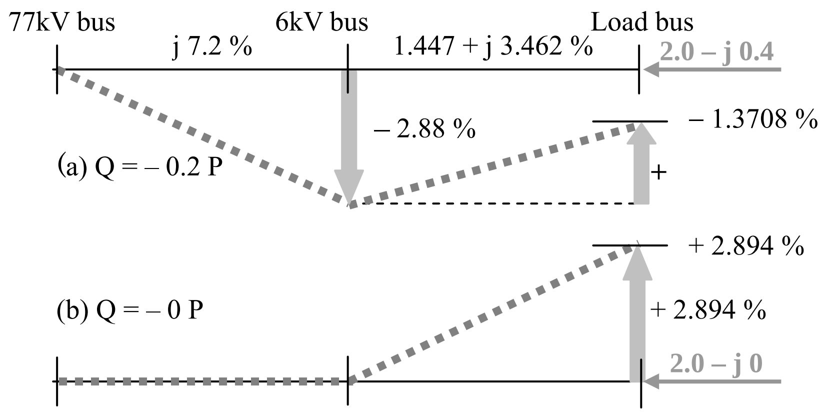

Fig. 8.18 Approximate voltage calculation (w/o tap change)

Voltage change at substation and load can be approximately calculated as Fig. 8.18.

In case of Q = – 0.2P, PV output change is 2.0 – j0.4 (at 10MVA base). Voltage rise by transformer: ΔV_T and that by distribution network: ΔV_D are approximately calculated as follows.

$$\Delta V_T = -\ 7.2\ \%\times 0.4 = -\ 2.88\ \%$$
$$\Delta V_D = 1.447\times 2.0 - 3.462\ \%\times 0.4 = +\ 1.5092\ \%$$

As the result, load voltage rise is: $\Delta V_L \fallingdotseq \Delta V_T + \Delta V_D = -\ 1.3708\ \%$. In case of LDC, LTC will raise 1 tap. Unit tap width is around 1.4%. Therefore, load voltage will be 1.4% higher than the figure, and will rise by 0.03%. In case of PGC, LTC will lower 2 taps, and as the result, load voltage will rise by 1.43%. It must be noticed that LDC brings smaller load voltage rise and fewer tap change than PGC.

In case of Q = – 0 P,　PV output change is 2.0 – j0 (at 10MVA base). Voltage rise by transformer: ΔV_T and that by distribution network: ΔV_D are approximately calculated as follows.

$$\Delta V_T = -\ 7.2\ \%\times 0 = 0\ \%$$
$$\Delta V_D = 1.447\times 2.0 - 3.462\ \%\times 0 = +\ 2.894\ \%$$

As the result, load voltage rise is: $\Delta V_L \fallingdotseq \Delta V_T + \Delta V_D = +\ 2.894\ \%$. In case of LDC, LTC will lower 2 taps. Therefore as the result, load voltage will rise by 0.09%. In case of PGC, LTC will not move, and as the result, load voltage will rise by 2.89%. It must be noticed that LDC brings smaller load voltage rise and fewer tap change than PGC also in case of Q = – 0 P.

However, it must be noticed that the calculations above neglect reactive power loss. In case of light load period, power flow magnitude is almost equal before and after PV output increase, and as the result, reactive power loss does not vary. On the contrary in case of heavy load period, power flow magnitude reduces much by PV output increase, and as the result, reactive power loss is much reduced, and voltage rise becomes larger. In such a case, slightly excessive compensation of Q = – 0.2P will absorb excessive reactive power, as the result, the slightly excessive compensation will not bring any harm but rather be favorable. So power-load balance in heavy load period and light load period were set here.

[Simulation] Since network voltage was maintained within regulation without using SVR3, its tap is fixed as 1.0 hereafter. Heavy load vs. Light load, Vector-LDC vs. PGC in LTC control, and Q = – 0.2P vs. Q = – 0 P in PV operation are considered. As total, 2*2*2=8 cases are simulated. The results are shown in Fig. 8.19 by highest and lowest voltage among the distribution network.

In case of LDC & Q/P = – 0.2, network voltage is maintained within 107V even in light load period with a large reverse power flow. On the contrary in case of PGC & Q/P = – 0.0, network voltage exceeds 107V in both light and heavy load periods. Lowest voltage is maintained 101V or higher successively. These simulation results are telling that voltage rise problem by PV integration does not mean necessity of new technologies but means mal-choice of existing technologies.

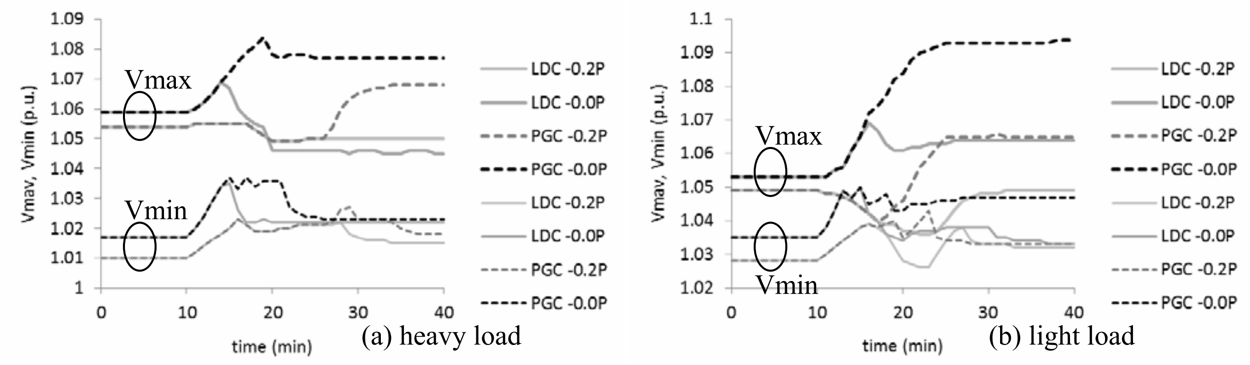

Fig. 8.19 Time variation of the highest and lowest voltage

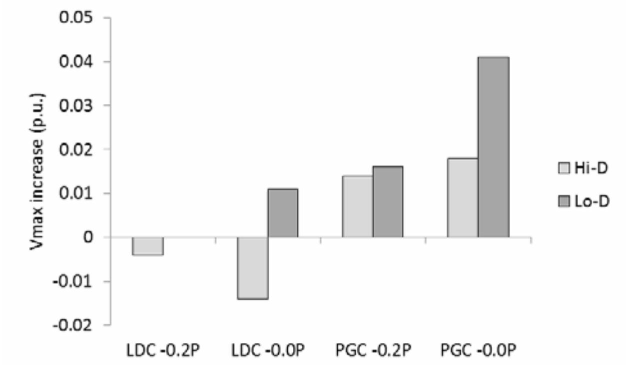

Fig. 8.20 Voltage rise of the highest by control types

Voltage rise of the highest voltage by the four control types are compared in Fig. 8.20. It is quite natural that PGC results larger voltage rise than LDC, Q/P = – 0.0 results larger voltage rise than Q/P = – 0.2, and voltage rise is larger in light load period than in heavy load period, because reverse power flow is far larger in light load period. .

Time variations of substation 6kV bus voltage and LTC tap position of distribution transformer are shown in Fig. 8.21. In case of LDC, load voltage is maintained, and as the result, substation voltage goes a little lower. In case of PGC, substation voltage is maintained. LTC lowers tap position most in case of LDC and Q/P = – 0.0, and raises tap position most in case of PGC and Q/P = – 0.2.

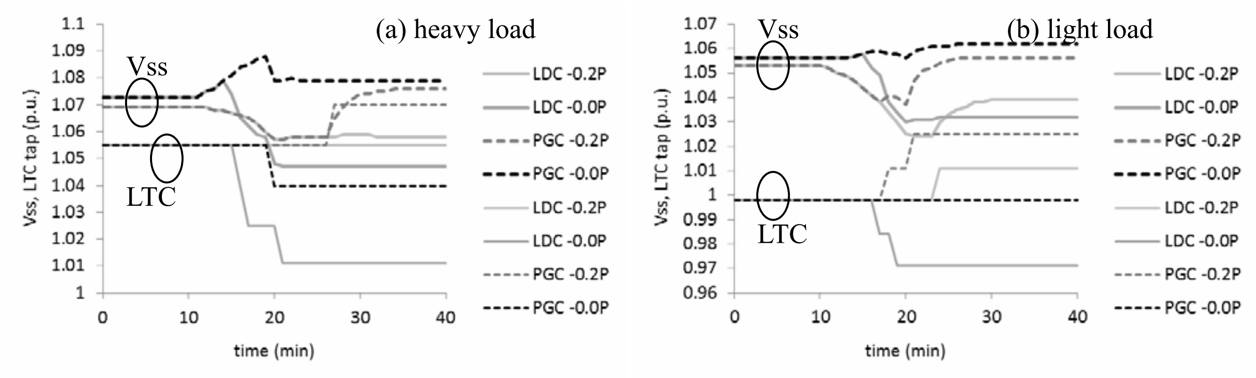

Fig. 8.21 Time variation of substation voltage and LTC tap

Number of tap position change by the four control types are compared in Fig. 8.22. In case of light load period, simulation result (Lo-D) agrees with approximate calculation result. In case of heavy load period (Hi-D), LTC lowers 1 tap in simulation result compared to approximate calculation result, because reactive power loss decreases by PV output increase. Number of tap change is small in LDC & Q/P=－0.2 case and PGC & Q/P=－0.2 case.

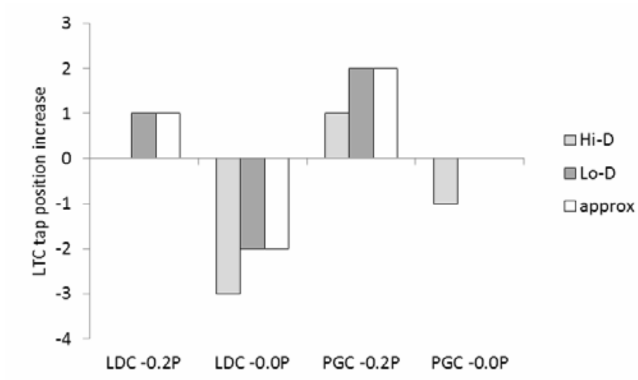

Fig. 8.22 Tap rise in LTC by control types

[Viewpoints of Loss and Energy Saving] It is well known that network loss becomes larger when PV operates lower power factor. Average network losses of the four control types in 2*2 = 4 scenes (that is, heavy/light demand and before/after PV output increase) are compared in Fig. 8.23. Certainly, Q/P = – 0.2 brings slightly larger loss than Q/P = – 0.0. However, it must be remarked that LDC brings much larger loss than PGC. Are LDC and Q/P = – 0.2 not favorable?

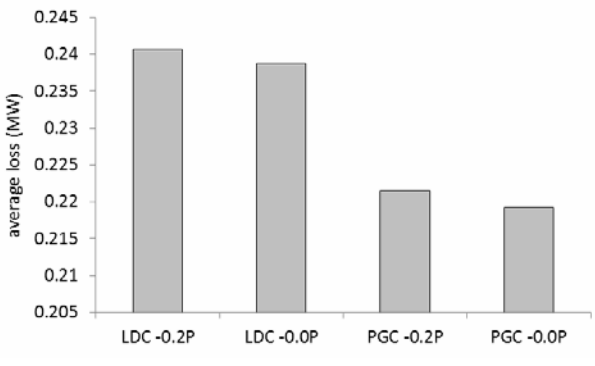

Fig. 8.23 Average loss by control types

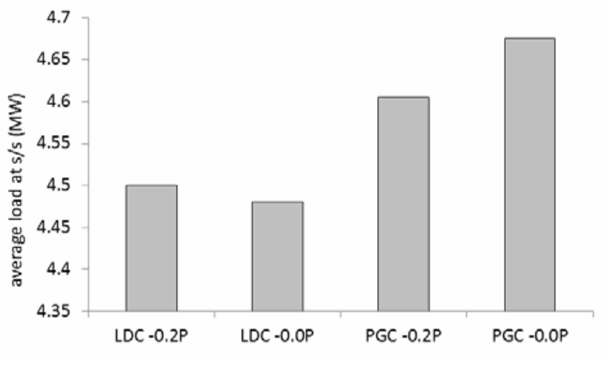

Fig. 8.24 Substation sending power by control types

However, average substation sending power by the four control types shows different result as Fig. 8.24.

Smaller substation sending power is favorable for energy saving, if a little lower voltage never spoils sound operation of electric equipments. LDC is favorable for energy saving than PGC.

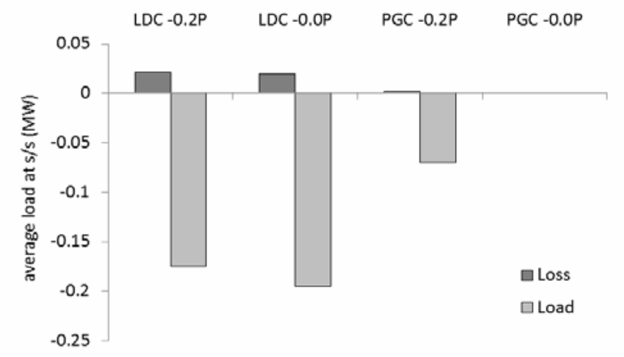

Fig. 8.25 Loss and sending power by control types

It must be noticed that graduation band is ten times larger in Fig. 8.24 compared to Fig. 8.23. For fair judge, loss and sending power are together shown in Fig. 8.25, making the most primitive PGC & Q/P = –0.0 control as reference. Difference by control type is much larger in sending power than in loss, and obviously, LDC is much favorable than PGC.

The cause of the result is the fact that loads do not have LTC in distribution network. Load voltage varies with network voltage. By measurements, load power varies almost proportional to load voltage (constant current character). In the example large reverse power flow sometimes appears. In case of PGC, network voltage varies higher, and as the result, load power varies also larger. To loosen voltage regulation (such as 110V or lower) has been found as a foolish idea in viewpoint of energy saving.

In Japan, efficiency regulation in three-phase induction motor will start. 2% efficiency rise in motor that consumes 50% of electricity will bring 1% energy saving. For the purpose, 1% lower voltage in distribution network will bring the same effect. Although a little higher voltage has not resulted complaints until now, recent PV penetration has resulted complaints of PV output suppression. Adequate correspondence to PV output suppression will solve sustained higher voltage in distribution network and will contribute to energy saving.

[Importance of Conservative Solution] Technology for mitigating RE's impact on power system has become fatally important now, when RE integration rapidly proceeds by FIT (Feed in Tariff) after east Japan disaster. Many aggressive solutions did not complete in time, because of cost and second effects. On the contrary, the author proposed conservative solutions that can be build up only by now available measures, showed the solution is sufficiently effective in now planning integration level, and as the result, has prepared a safety net.

System engineering teaches conservative solution is indispensable. The first reason is that it will be a safety net if the other solutions have failed. The second reason is that it becomes reference for evaluating haw the other solutions is excellent. Since the author is an artisan looking after existing network, issues must be solved. Research is no more than a measure. Slow proceeding in solution may be favorable for employed research scientist's lasting employment, but is not suitable for artisan and existing network. Thus, conservative solution seems to be indispensable as insurance for the time of being.

[Example of wrong modeling] There was some technical reports (4) made by professional research scientists employing quite low impedance in distribution transformer. At first, impedance of 20MVA transformer was set as 3.75% at 10MVA base (almost half of reality) and the transformer supplied only one feeder. Perhaps they had forgotten to make the transformer impedance five times larger. So, to examine the results caused by wrong modeling, some simulations were made by setting distribution impedance transformer as j3.6% (1/10). In fig. 8.26 to 8.29, simulation results in light and heavy load periods, in the most sophisticated case (vector LDC and PV's leading power factor) and in the most primitive case (PGC and PV's unity power factor) are introduced.

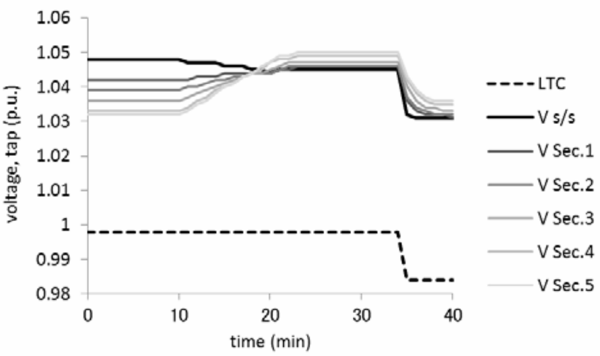

Fig. 8.26 Tap/voltage (light load), LDC, Q= -0.2P

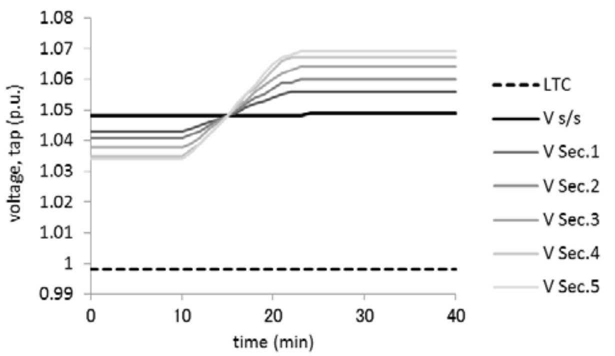

Fig. 8.27 Tap/voltage (light load), PGC, Q= -0.0P

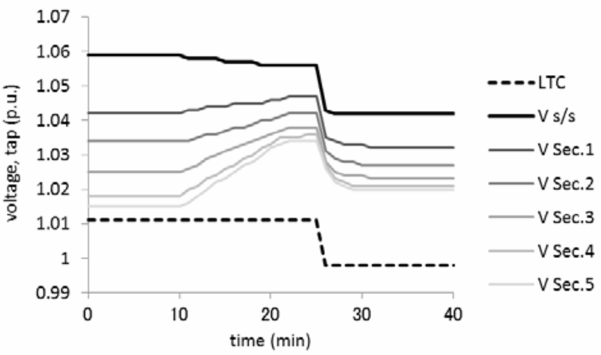

Fig. 8.28 Tap/voltage (heavy load), LDC, Q= -0.2P

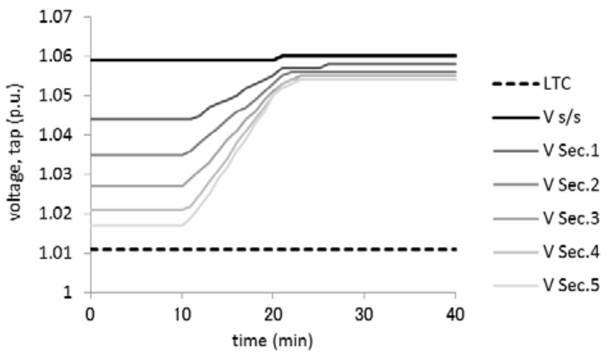

Fig. 8.29 Tap/voltage (heavy load), PGC, Q= -0.0P

In spite of PV's leading power factor, load voltage rises as PV output increases. Q= -0.2P leading power factor turns from over-compensation (correct model) to under-compensation (wrong model). Although, temporary high voltage appeared in PGC and unity power factor case, but does not appear in wrong model.

Alike former studies voltage regulation ranking of the four control schemes are shown in Fig. 8.30. LDC and leading power factor is the best, but the results may be meaningless. Of course, such contents cannot be published as a scientific paper.

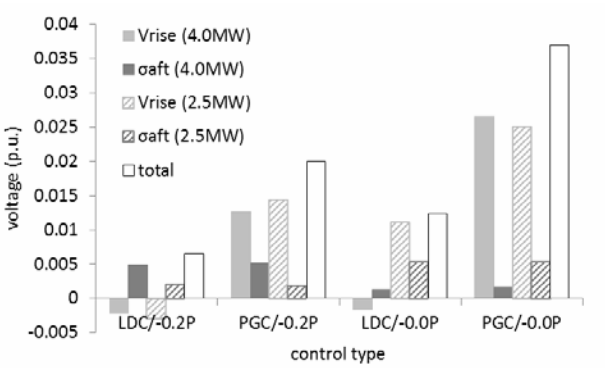

Fig. 8.30 Ranking of the 4 controls (voltage)

Economy of PV's Leading Power Factor Operation

Instead of Q = -0.2P operation of all Japan 53GW rated output PVs, SVCs are supposed. Necessary capacity is 53GW * 0.2 = 10.6GVar. Cost of SVC itself is around ¥30k/kVar. Therefore, total SVC cost is 10.6GVar * ¥30k/kVar = ¥318 billion. This is considerable.

For leading power factor operation, slightly larger inverter capacity is needed. In case of Q = -0.2P, the capacity is 1.0198 of rated output. If PV voltage rises to 102% by generating, current is reduced to 100%, and incremental capacity of inverter is not needed. This favorable result comes from light leading power factor.

In fact, inverter having leading power factor operation function was already developed. But it perform very hard leading power factor such as 85% (Q = -0.62P) until voltage is reduced to 107V or lower. As the result, active power output is curtailed. To avoid the curtailment, larger capacity inverter is needed. The traditional leading power factor had naturally poor reputation, and did not penetrate. What is the cause of the failure? It is impossible for one PV having very small capacity compared to power system to maintain its voltage by only itself. Small PVs must unite. Flag of the unity is the promise, light leading power factor operation. One for all. Even if voltage of the PV is normal, it operates in leading power factor for all. All for one. PV with the highest voltage may avoid output curtailment by effort of all.

High PV Penetration in Existing Network [1]

In existing distribution network model shown in Fig. 8.31, voltage profile with high PV penetration is simulated. One feeder is divided into several to 10 sections. Each section is aggregated Y-connection method. The example network contains much amount of residential demand. If PV penetrates mainly into residential customers, The network will be the most PV rich in the utility. If PVs fully generates, distribution transformer (bank) becomes light reverse power flow.

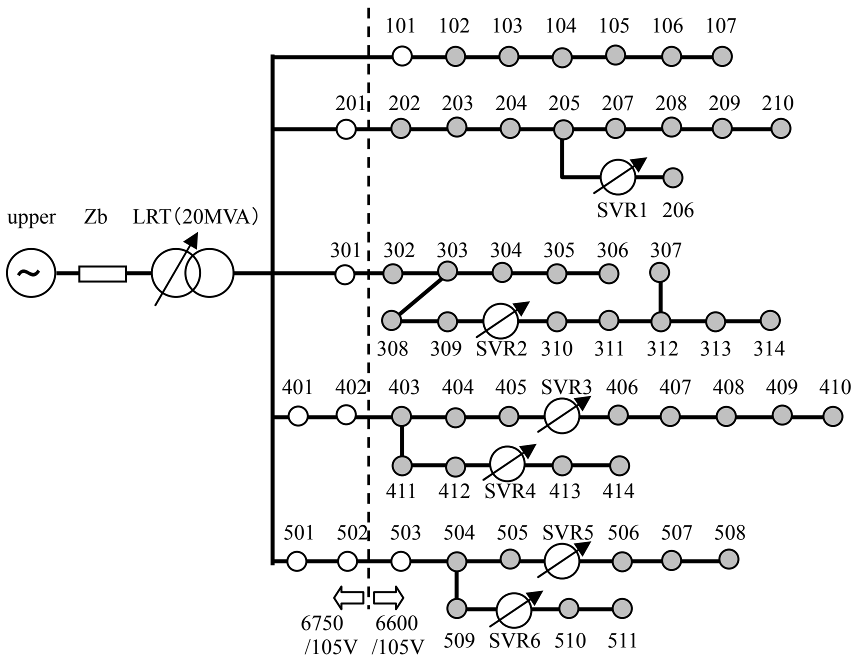

Fig. 8.31 Model of an existing distribution network

Before assessing PV impacts, model must be verified by contrasting simulated results to measured facts. In many studies, models of existing networks are not used but fictitious models are used. Even if models of existing networks are used, they rarely verified by measured fact. The author thinks that those attitudes have spoiled credit of simulation. Verification results are shown in Fig. 8.32. For simulation, CRIEPI V-method tool is employed. In many time duration error is almost zero. In some time duration around ± 1% error is seen. One step of LRT tap is 1% or slight large. The error means that some error exists in time of tap change. 2% or more voltage error is quite rare. Accuracy is good. One of the reasons is modeling of upper system. Upper system consists of not only voltage source but also its internal impedance Zb. The accuracy is lost by simpler models. Of course, measured active and reactive at bank secondary are distributed to each section based on contracted power of customers and empiricism gained from field work. MV capacitors at customers are considered independently from reactive load.

In the example network, two cases: Q = 0 or Q = -0.2 operation of PV, and two cases: scheduling or vector LDC on LRT, totally 2 bay 2 equal 4 cases are examined by simulations. The results are shown in Fig. 8.33. Measured PV output data on a clear day is multiplied without considering smoothing effect and is used as aggregated PV output of each section. In the figure, the highest and lowest voltages under the bank and substation bus voltage are shown. Only in case of Q = -0.2P and vector LDC, all voltages are kept 107V or lower during the whole day.

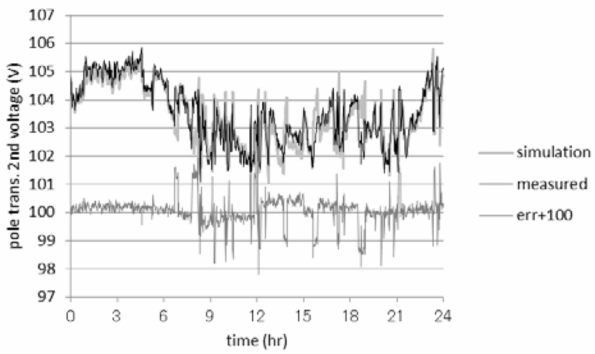

Fig. 8.32 Comparison of measured and simulated voltage

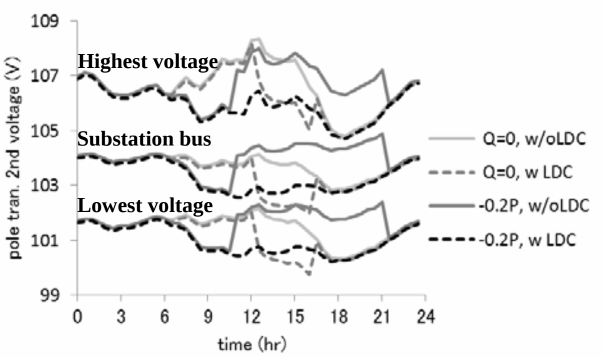

Fig. 8.33 Effect of PV's leading power factor and vector LDC

Effect of PV's Leading Power Factor Operation on Fast Fluctuation (2)

Here above fast output fluctuation of PV was not considered. However, PV sometimes shows large and fast output fluctuation, which is not sufficiently smoothed out in small area fed by a feeder. LDC regulates voltage using tap control, which cannot follow PV's fast fluctuation. As the result, fast voltage fluctuation may remain uncompensated.

Results of voltage simulation when PVs make fast output fluctuation are shown in Fig. 8.34. Without PV's leading power factor operation (Q = 0), large voltage fluctuation remains, and voltage sometimes exceeds 107V temporarily. On the contrary, PV's leading power factor operation (Q = -0.2P) can suppress not only slow voltage deviation but also fast voltage fluctuation, and voltage is suppressed at 107V or lower.

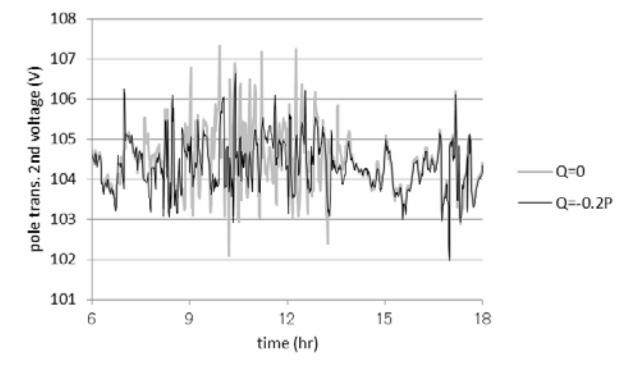

Fig. 8.34 Voltage profiles by PV's fast output

So long as PV's output variation is not so fast, voltage rise by highly penetrated PVs can be avoided. However, studies above assume that PVs penetrate to houses in even distribution. In case of very fast fluctuation of PV output, uneven distribution, and so on must be studied. PV's leading power factor operation will surely still be an effective measure in those studies.

Positive Effects of PV's Leading Power Factor Operation on Trunk System (2)

Effects of PV's leading power factor operation on example trunk power systems are evaluated. For conservative evaluation, voltage support effect of outer system is ignored. Capacitor is equipped at secondary bus of each interconnection transformer (drawn in black) feeding each load, and regulates primary voltage of the transformer by switching on and off. Interconnection transformer and distribution transformer (drawn in gray) have LTCs (on-Load Tap Changer), which regulate secondary bus voltage. Transformers in EHV system also have LTC, but those are controlled VQC (Voltage and Reactive power Control) of whole system, therefore, those taps are assumed to not change here. To simulate the whole system is difficult. Therefore, some aggregation is needed. Here, Y-connection aggregation that considers all series impedance of network from generators to load terminals is employed.

Terminal voltages of generators in trunk system are regulated by AVR (Automatic Voltage Regulator). Power factors of local generators in secondary system (66kV class) are regulated by APFR (Automatic Power Factor Regulator).

Total rated output of PV is assumes as 30% of peak demand. If Japan plan penetrating 53GW PV is realized, such a situation appears. During 10 min to 20 min, PV output increases from very low to rated output. Load voltage will rise, capacitors will be switched off, and LTC will step tap down. As PV's power factor, Q = 0, Q = -0.2P, and Q = -0.4P are examined.

The author tried simulation on 10 power systems in Japan. No considerable differences are seen among those systems. However, the 10 systems seem to be classified into 4 groups. Therefore, one example is introduced from each group respectively.

[Example System C] Structure of the system is shown in Fig. 8.35. The system consists of 20 generators and 17loads, and interconnects to an outer system.

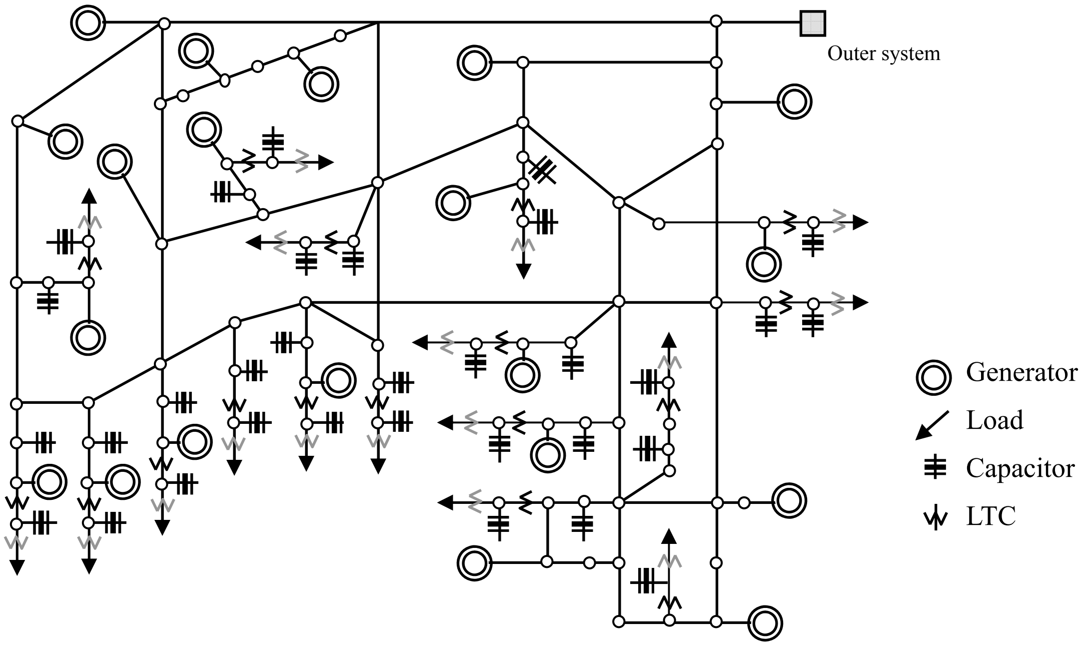

Fig. 8.35 Structure of example system C

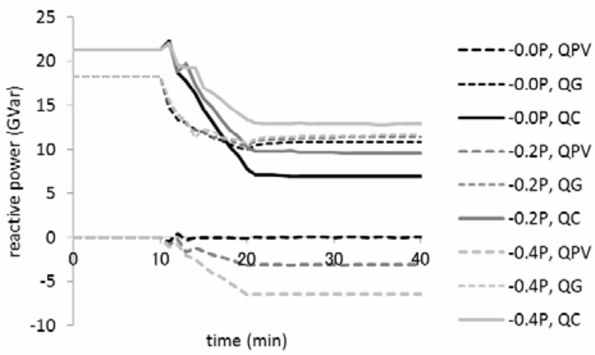

Fig. 8.36 Time variation of reactive power (example C)

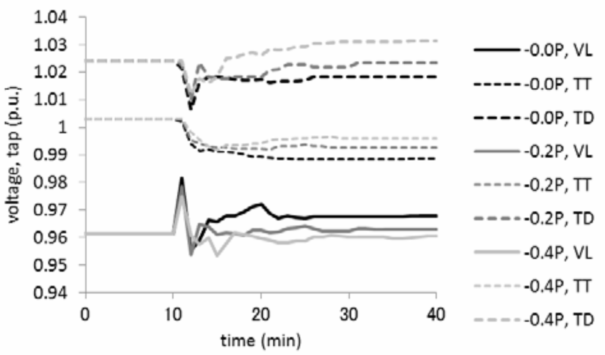

Fig. 8.37 Time variation of voltage and tap (example C)

Time variations of reactive power of all PVs (QPV), that of all generators (QG), and that of all capacitors (QC) are shown in Fig. 8.36. QG hardly changes by PV power factor. On the contrary QC decrease becomes smaller as PV leading power factor becomes strong (0 to -0.4). Average load voltage (VL), average interconnection transformer tap position (TT), and average distribution transformer tap position (TD) are shown in Fig. 8.37. VL is maintained well by capacitor switching-off and tap down. Burden of tap change becomes light by PV's leading power factor operation.

[Example System E] Structure of the example system is shown in Fig.8.38. The system consists of 20 generators and 20 loads, and interconnects to 2 outer systems.

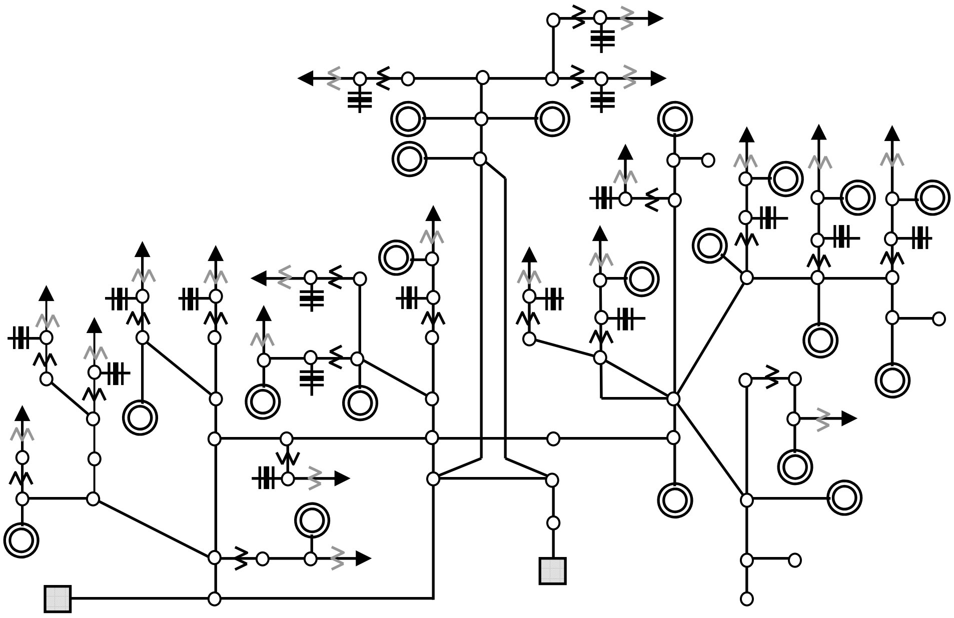

Fig. 8.38 Structure of example system E

Time variations of reactive power of all PVs (QPV), that of all generators (QG), and that of all capacitors (QC) are shown in Fig. 8.39. QG hardly changes by PV power factor. On the contrary QC decrease becomes smaller as PV leading power factor becomes strong (0 to -0.4). Average load voltage (VL), average interconnection transformer tap position (TT), and average distribution transformer tap position (TD) are shown in Fig. 8.40. VL is maintained well by capacitor switching-off and tap down. Burden of tap change becomes light by PV's leading power factor operation.

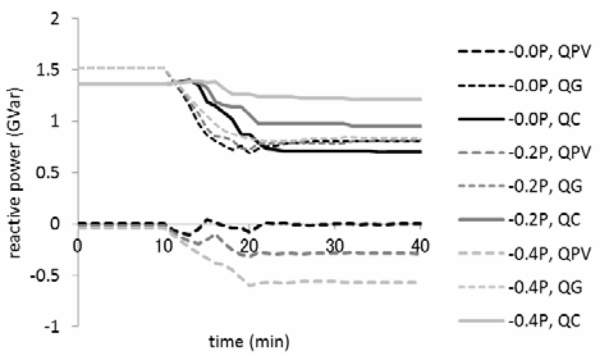

Fig. 8.39 Time variation of reactive power (example E)

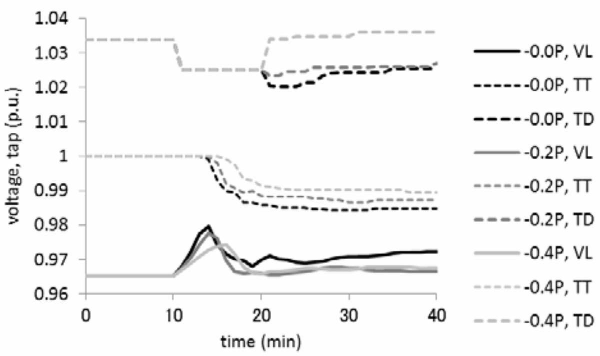

Fig. 8.40 Time variation of voltage and tap (example E)

[Example System H] Structure of the example system is shown in Fig. 8.41. The system consists of 11 generators and 8 loads, and interconnects to one outer system.

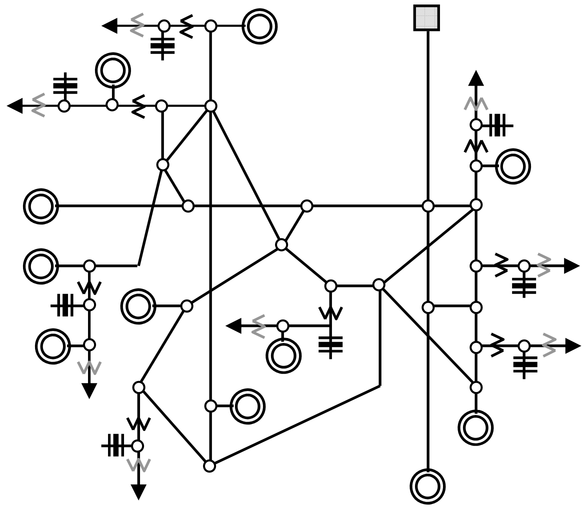

Fig. 8.41 Structure of example system H

Time variations of reactive power of all PVs (QPV), that of all generators (QG), and that of all capacitors (QC) are shown in Fig. 8.42. QG change is, slightly different from former two examples, considerably mitigated by PV's leading power factor operation. QC decrease is a little more mitigated by PV leading power factor operation. Average load voltage (VL), average interconnection transformer tap position (TT), and average distribution transformer tap position (TD) are shown in Fig. 8.43. VL is maintained well by capacitor switching-off and tap down. Burden of tap change becomes light by PV's leading power factor operation.

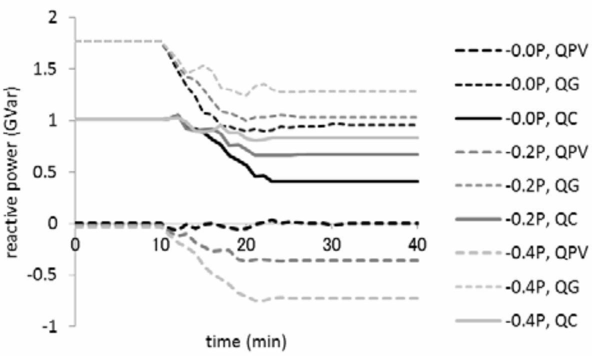

Fig. 8.42 Time variation of reactive power (example H)

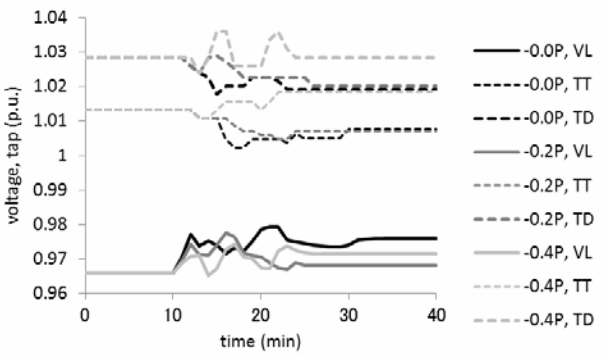

Fig. 8.43 Time variation of voltage and tap (example H)

[Example System J] Structure of the example system is shown in Fig. 8.44. The system consists of 6 generators and 10 loads, and interconnects to no systems.

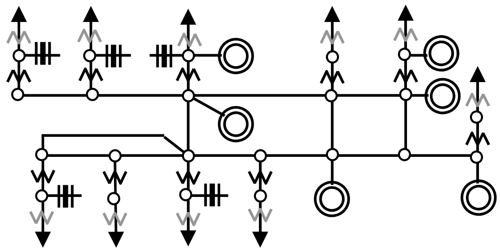

Fig. 8.44 Structure of example system J

Time variations of reactive power of all PVs (QPV), that of all generators (QG), and that of all capacitors (QC) are shown in Fig. 8.45. QG change is considerably mitigated by PV's leading power factor operation. QC decrease is slightly less mitigated by PV leading power factor operation. Average load voltage (VL), average interconnection transformer tap position (TT), and average distribution transformer tap position (TD) are shown in Fig. 8.46. VL is maintained well by capacitor switching-off and tap down. Burden of tap change becomes light by PV's leading power factor operation.

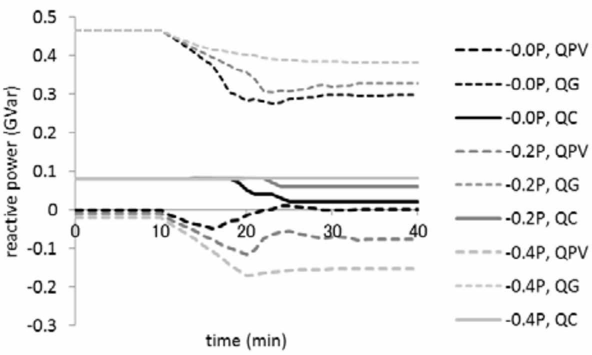

Fig. 8.45 Time variation of reactive power (example J)

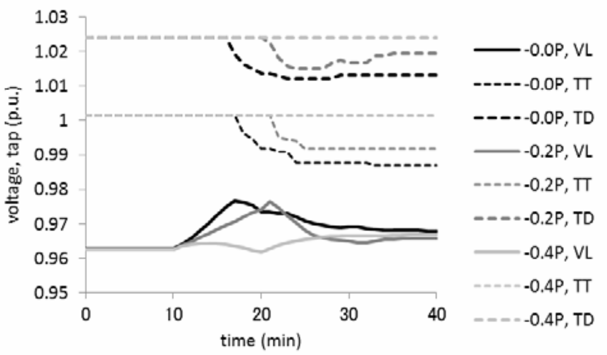

Fig. 8.546Time variation of voltage and tap (example J)

[Equivalent Reactance Xeq] 10 power systems analyzed show some common tendencies for PV's leading power factor operation. At first, generator reactive power QG does not depend on level of PV's leading factor as shown in Fig. 8.47.

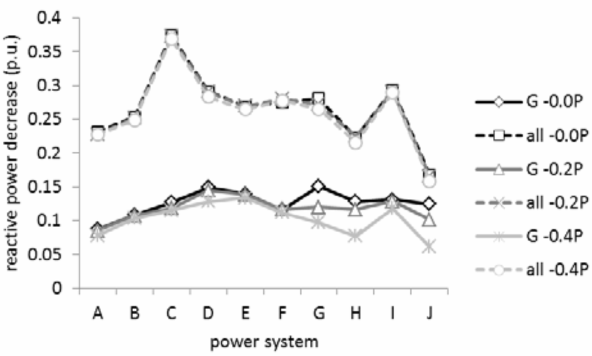

Fig. 8.47 Reactive power decrease by PV's leading P.F.

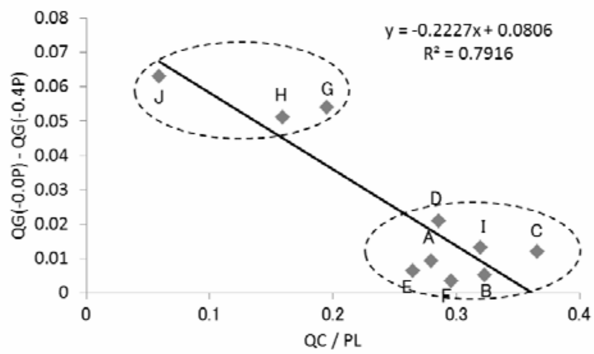

Fig. 8.48 Gen. reactive power decrease by capacitor amount

However in G, H, and J, QG decreases due to PV's leading power factor considerably more or less. The difference may come from capacitor total capacity by system total load. Result of the trial analysis is shown in Fig. 8.48. System G, H, and J that has relatively small amount of capacitor show smaller QG decrease by PV's leading power factor from Q = 0 to Q = -0.4P. Considerably high correlation factor (R^2 = 0.7916) tells that the explanation is somewhat meaningful.

At second and the last, total reactive power decrease is almost not dependent to PV's leading power factor. The tendency is common to the all 10 systems. The fact tells that the reactive power decrease is caused mainly by reactive power loss decrease in network collective reactances from all power sources to all loads. Then, amount of the collective reactance (X) is tried to be identified. Total load (P_L) is assumed to be kept constant. Total reactive power loss (Q_0) at low PV output (P_{PV0}) and total reactive power loss (Q_1) at high PV output (P_{PV1}) are calculated as follows respectively.

$$Q_0 = X (P_L - P_{PV0})^2 \qquad Q_1 = X (P_L - P_{PV1})^2$$

Making difference of the two equations, the reactance X is obtained as follows.

$$X = \frac{Q_1 - Q_0}{(P_L - P_{PV1})^2 - (P_L - P_{PV0})^2}$$

However, comparison of the 10 systems is impossible by using the raw X. Therefore, X is normalized by total load (P_L) and translated to Xeq as follows.

$$Xeq = X\,P_L = \frac{\dfrac{Q_1}{P_L} - \dfrac{Q_0}{P_L}}{(1 - \dfrac{P_{PV1}}{P_L})^2 - (1 - \dfrac{P_{PV0}}{P_L})^2}$$

The Xeq is called as "equivalent reactance" hereafter. Reactive power decrease by PV output increase is explained by the reactance Xeq as shown in Fig. 3.49. The result shows high correlation factor (R^2 = 0.9561). The result is natural because of origin of Xeq. 10 example systems are classified into four groups. In example system C with large Xeq, reactive power decrease is also large. On the contrary in example system J with small Xeq, reactive power decrease is also small. Example systems D, E, F, G, and I form the second group, and example systems A, B, and H form the third group. It is the facts above that the 10 example systems are classified into four groups.

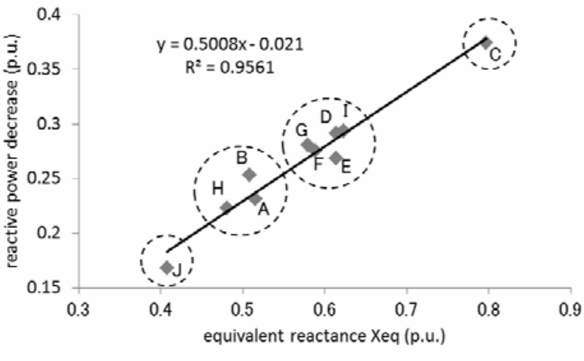

Fig. 8.49 Reactive power decrease by Xeq

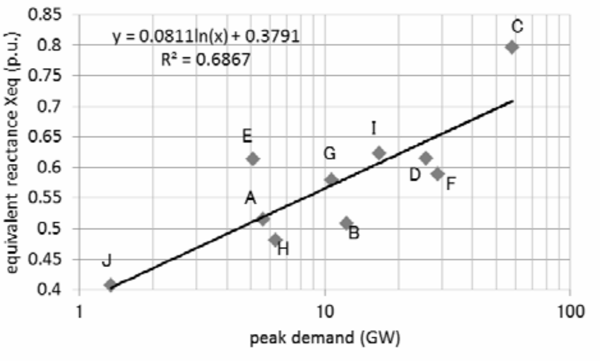

Fig. 8.50 Xeq by system size

What factor rules the Xeq value? Since Xeq is the reactance from all power sources to all loads, it is also an index of remote power source. Therefore, it becomes higher in such a system that has much power sources at high voltage like 500kV remote from load center. Such a system must be a gigantic system. Then, correlation between peak demand and Xeq are examined as shown in Fig. 8.50. Correlation factor is not high (R^2 = 0.6867) but clearly positive correlation exists. The insight above is correct.

Since reactive power variation of generator is made by static electric circuit, no maintenance is needed by reactive power variation. On the contrary since reactive power variation of capacitor is made by switching of circuit breaker, very often reactive power variation results also often maintenance. Cost of maintenance may be not high, but some part of network must be stopped as planed in advance without causing problems on reliability. Burden for the care is rather troublesome. Therefore, system with smaller switched out capacitor amount is more favorable system. System A, H, and J seem to be well designed.

[Evaluation of PV's Leading Power Factor Operation] Switched-off capacitor amount ΔQ_C by PV's leading power factor about 10 example power systems are summed as Fig. 8.51. Since switched-off amount is expressed by per unit method at total demand base, influence of system size is excluded. At a glance it is recognized that ΔQ_C is large in system C and small in system J. However, slope of ΔQ_C by Q/P ratio of PV output is not so much different by system. That is, PV's leading power operation shows positive effect in every power system.

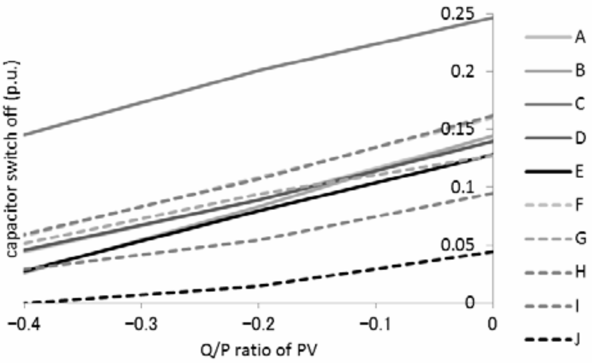

Fig. 8.51 Capacitor decrease by PV's leading P.F.

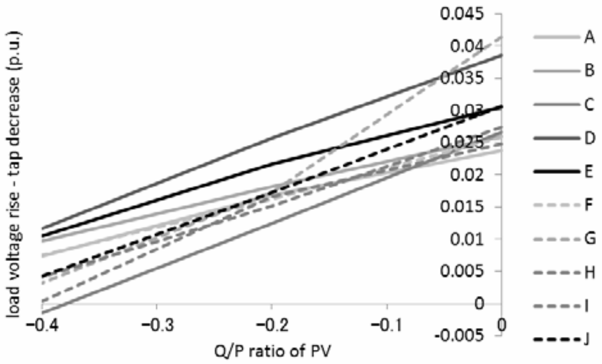

Fig. 8.52 Voltage & tap change decrease by PV's leading P.F.

As an index for total assessing, variation of load voltage and taps on interconnection and distribution transformers is used here as follows. Here, ΔV_L is load voltage rise and ΔT_T and ΔT_D are tap-position decreases on interconnection and distribution transformers respectively.

$$I_{VT} = \Delta V_L - \Delta T_T - \Delta T_D$$

By PV output increase, load voltage will rise and tap position will go lower. If so, total assessment can be made by subtracting the latter from the former. The indices by PV's Q/P ratio of the example 10 systems are shown in Fig. 8.52. In every power system, voltage and tap change is mitigated by PV's leading power factor. Thus, PV's leading power factor has positive effect also on mitigating voltage and tap change.

Summing up studies above, PV's leading power factor operation of Q = -0.4P or lighter is favorable for trunk power system, and no negative effects are seen. Even a little heavier leading power factor Q = -0.4P is not so bad totally considering tap operation on transformers. However it must be remembered that heavier PV's leading power factor needs slightly larger PV's inverter capacity and some uneconomic. The author thinks that light leading power factor Q = -0.2P that was judges as favorable for local system in the beginning part of the chapter is also favorable for trunk system.

Importance of Highly Penetrated PV's Leading Power Factor Operation

Until today, Japanese government and utilities have assessed voltage rise due to PV only in low voltage network. Certainly in the beginning of PV penetration, voltage problem appears by concentrated PVs under a common pole transformer. The problem can be considerably solved by equipping pole transformer on every pole and use no low voltage lines. Since low voltage has smaller reactance than resistance, PV's leading power factor cannot show much effect on mitigating voltage rise in low voltage network. Therefore, at the beginning of PV penetration, the focused measure was not PV's leading power factor but pole transformer on every pole.

However, when PV's high penetration becomes realistic, circumstance changes. By investigation is the second oil shock, 40% of distribution network loss is copper loss in MV line and 30% is iron loss in pole transformer. Copper loss in pole transformer, LV line, and drop wire is not large. Among them, iron loss is a parallel loss and has no relation with voltage rise. As the result, most reactive power loss is caused in HV line considering that reactance of MV line is almost twice of resistance in case of copper 80sq wire. Thus, although the fact that the method of "pole transformer on every pole" is still indispensable for concentrated PVs is remain unchanged, "PV's leading power factor" becomes indispensable for voltage rise mitigation measure as well as "vector LDC" on distribution transformer's tap operation, when PV considerable penetrates and high penetration become realistic.

References

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(2) M. Ishimaru, H. Tamachi, & S. Komami: "Positive Effects of PV's Constant Leading Power Factor Operation in Power System", IEEJ trans. PE, Vol. 132, No. 7, pp. 615-622, 2012 (in Japanese, to be translated in English by Wiley)

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