MV overhead feeder automation

by John Cossey, Nu-Lec Industries

Electricity providers are under immense pressure to improve the reliability of supply to their customers.

Providers have a number of options available to improve supply reliability including additional primary substations, additional feeder circuits, vegetation management, covered conductor, underground circuits, better feeder automation and network configuration.

Additional primary substations and feeder circuits reduce the number of consumers affected by a fault, covered conductor and underground circuits reduce the number of faults, but are all very expensive options. Vegetation management is an operational issue and should be well attended to in any event.

This paper examines better feeder automation and network configuration.

**Feeder automation sophistication**

In an effort to improve reliability of supply, providers are rethinking the levels of sophistication deployed in their medium voltage (MV) overhead feeders. Studies of faults on overhead feeder networks have shown that 60 – 70% of the faults are transient.

Examples of transient faults include conductors clashing in the wind, tree branches falling on overhead conductors, animals or birds and lightning strikes.

An auto-reclose cycle should clear a transient fault without interrupting supply to the customer. In most cases no further operator assistance would be required to clear the fault. Some faults are however permanent. Examples include distribution equipment failures and fallen power lines due to motor accidents or storms. Protection equipment is designed to minimise damage by interrupting supply to a segment containing a fault. The supply will remain off until the fault is removed and the protection equipment is turned back on. During a permanent fault the following actions would typically be taken to minimise the effects of the fault:

- Protection equipment (circuit breaker or recloser) would interrupt supply to the affected segment/s of the feeder.
- Determine the faulty segment of the feeder.
- For looped networks isolate the faulty segment by opening the switchgear upstream and downstream of the fault.

- Reconfigure the network for alternative power flow.
- Restore power upstream of the faulty segment.
- If an open loop network is used, close the open point to restore power downstream of the faulty segment.
- Maintenance crews remove the fault.
- Restore the network to the normal configuration.

It is possible that outages can last for hours and even days. To minimise the duration of the outages it is necessary to quickly identify the exact location of the fault and to provide alternative power supplies to segments not containing the fault. This can be done manually or by using sophisticated switchgear controllers which could substantially reduce the outage time.

This paper explores the effectiveness of feeder segmentation and considers the effects of using different arrangements or types of switchgear to construct an overhead MV network run as an open ring.

Four possible scenarios giving increasing levels of automation sophistication are compared for cost and benefits, and operational risks under fault conditions:

- Telecontrolled switches in a remotely controlled, but not necessarily automated network
- Reclosers and sectionalisers in an automated, but not necessarily remotely controlled network.

A glossary is provided at the end of the document.

**Feeder segmentation**

Reliability gains can be made by increasing the protection sophistication. This is not limited to the latest protection algorithms. It also includes breaking the feeder into smaller segments. This reduces the number of customers per segment and therefore the number of customers affected by a fault.

**Increased number of segments per feeder**

Consider a theoretical radial feeder. Assume that the probability of a fault is the same along the length of the feeder. By dividing the feeder into multiple segments the probability that a fault would occur in a specific segment is:

\[
P_f = P_s \times \frac{L_s}{L}
\]

where

- \( P_s \) = the probability that a fault would occur anywhere on the feeder.
- \( L \) = the length of the feeder.
- \( L_s \) = the length of the segment.
- \( P_f \) = the probability that a fault would occur anywhere on the feeder.

It is possible to calculate the impact when the feeder is divided into multiple segments of equal length (Table 1).

Unfortunately these improvement figures do not tell the full story. To get the full picture it is necessary to revisit the basic radial feeder, look at the probability of an outage in each segment and then expand the theory to a looped network.

**Radial feeder**

Table 2 shows how the outages in each segment are affected by the number of
faults in that segment and the faults occurring in upstream segments. Loop networks are used to reduce the number of outages for segments located further away from the substation and to overcome this stepped increase in outages.

To improve the reliability of supply. However, not all customers benefit equally from this investment and looped networks are often used to improve supply reliability throughout the feeder.

Feeder segmentation is achieved by using different technologies ranging from sophisticated reclosers and sectionalisers through telecontrolled load-break switches to manually operated air-break switches. The technology used in feeders differs from country to country and is also affected by the population density (number of customers per segment). In reality underground circuits may be used in the inner city, reclosers in substations and outer city feeders and sectionalisers in rural feeders.

Subsequent sections of this paper discuss the benefit and operation of each technology based on a common feeder topology.

Basic operation during fault conditions

When a permanent fault occurs the substation circuit breaker or recloser trips automatically to interrupt supply to the affected feeder; an operator in the control room identifies the faulty segment of the feeder by using the FPI indication displayed in the control room; opens (via a communications network such as optical fibre) the nearest upstream and downstream switches to isolate the faulty segment; reconfigures the protection in substation breakers; closes the substation circuit breaker to restore power upstream of the faulty segment; and closes the normally-open point to restore power downstream of the faulty segment.

Power is restored to the healthy parts of the network and it is possible for the operator to despatch the maintenance crews to the faulted segment of the feeder to remove the fault. Once the entire feeder is healthy the operator can open the normally-open point and close the telecontrolled switches to restore the network to the normal configuration.

Operational risks

The reaction time of the control room has a significant impact on the feeder restoration times. In practice the reaction time is influenced by the availability of an operator, enough operators to monitor and react during periods of extreme fault activity - such as large storms, reliability of communications to monitor FPI indication and to control the switchgear, feeder complexity and level of automation in control room and network.

However, if managed correctly control room operations may not degrade the operational efficiency of this type of network.

Fault passage indicators (FPIs) are the “eyes” of the operator. When the operator does not have a clear understanding of the fault

<table>
<thead>
<tr>
<th>Number of segments</th>
<th>Segment fault probability</th>
<th>Improvement</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>( P_x = P_1 )</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>( P_x = P_x \times 1/2 )</td>
<td>( P_x / P_1 = 50% )</td>
</tr>
<tr>
<td>3</td>
<td>( P_x = P_x \times 1/3 )</td>
<td>( P_x / P_2 = 66% )</td>
</tr>
<tr>
<td>4</td>
<td>( P_x = P_x \times 1/4 )</td>
<td>( P_x / P_3 = 75% )</td>
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</tbody>
</table>

Table 1: Reliability improvement.

<table>
<thead>
<tr>
<th>Seg</th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>F</td>
<td>MP1</td>
<td>MP2</td>
<td>NO</td>
</tr>
</tbody>
</table>

Where “F” represents the switchgear closest to the substation and “MP” represent switchgear anywhere along the feeder.

Probability of a fault in each segment is:

\[ P_x = P_x \times 1/2 \]

Probability of an outage in each segment is:

\[ P_x = P_x \times 1/3 \]

Where \( P_x \) is the probability of losing supply at the primary substation. \( P_x \) should be negligible and this simplifies the probability of an outage in each segment. (Notation: \( P_x = P_x + P_1 + P_2 + P_3 \))

For equal segment lengths and by using \( P_x = P_x \times (2/L) \) the above is possible to show what percentage of permanent faults will affect each segment. For feeders with four segments:

<table>
<thead>
<tr>
<th></th>
<th>4</th>
<th>25%</th>
<th>50%</th>
<th>75%</th>
<th>100%</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>33%</td>
<td>60%</td>
<td>100%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>50%</td>
<td>100%</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Notice how the probability of an outage increases further away from the substation. From this example it is clear that not all customers benefit equally from additional segments on the feeder. Only customers connected to the first segment will experience the improvements calculated in Table 1.

Table 2: Radial feeder.
location the operational efficiency of the network will be reduced. FPI functionality can be incorporated in the switchgear. These utilise switchgear mounted current transformers (CTs) and sensing electronics to detect fault conditions.

FPIs can also be separate from the switchgear and these typically measure the magnetic field around the transmission line and are simply clipped onto the conductor making it extremely easy to install. The major advantage of clip-on FPIs is that they can be installed anywhere along the feeder and it is possible to relocate them as requirements change.

Two risks are associated with FPIs – false indication and no indication at all.

False indication is the situation where the FPI indicates a fault without a fault being present. This can be caused by inrush currents during switching operations and reclosing cycles. In general no indication can occur when low level phase and earth fault conditions are not detected by the FPIs resulting in the absence of FPI indication. It is possible to overcome these risks by matching the detection capabilities of the FPI to that of the primary protection devices in the feeder.

It is also possible that the absence of indication is caused by communication failure.

In either case, an operator, may be left with a dead feeder and misleading FPI indication on the mimic panel. This will mislead the operator as to the actual location of the faulted segment resulting in incorrect switching operations and increased time taken to restore power. The integrity of the telecontrolled switch network relies wholly on the availability of communications and this key part of the system affects all aspects of network operation. During a fault condition the protection equipment will trip and without communications the operator will not be able to reconfigure and restore supply. Maintenance crews will have to locate the fault and manually reconfigure the network by driving to each unit before power is restored. This will take many hours and will cause unacceptable delays in restoring power to the customers.

Advantages of telecontrolled switches

- Relatively low initial cost of switchgear
- Much lower outage times when compared with manually-operated switches (no communications).

Disadvantages of telecontrolled switches

- Faults affect all customers connected to the feeder.

As the switches are manually, remotely operated, the duration of the outage is dependent on the response time of the operator.

Expensive communications infrastructure.

Operation is highly dependent on the integrity of the communications network.

All faults cause substation circuit breaker operation – this results in a shorter service life.

Protection functionality is limited. Only one circuit breaker to detect high fault levels close to the substation and low fault levels some distance away.

Low fault levels can go undetected by circuit breaker and FPIs, e.g. Sensitive Earth Fault (SEF).

Evolving sophistication

Where a communications network is expensive or difficult to implement, and in more critical parts of networks, there is a move away from telecontrolled switches to “infilling” with reclosers and using the telecontrolled switches as sectionalisers. This introduces protection and automation sophistication to the feeder.

An example of a more “sophisticated” feeder is where load break switch / sectionalisers are used instead of telecontrolled switches. Communications is not essential to the operation of feeders where reclosers and sectionalisers are used. These networks can be automated to improve response times and do not have to be remotely-controlled.

Sectionalising switchgear

To analyse the use of sectionaliser logic in a feeder let us consider the same open loop topology from the previous example but replace the telecontrolled switches with sectionalisers switches.

A sectionalis switch (sectionalis) is a load break switch capable of monitoring both current and voltage on all three phases. The switch is combined with a controller capable of detecting through-faults and upstream recloser operation. The current sensors count the number of fault currents which pass through the switch, and the voltage sensors detect when the line is deenergised due to upstream recloser operation. When the programmed number of reclosing operations occurs, the controller opens the sectionalis during the dead time to isolate the downstream fault.

These networks are graded by number of operations. That is upstream devices are set to open at a higher number of supply interruptions (SI) than the downstream devices. Therefore in this example the SI counter for the sectionalisers is set to 3, 2 and 1 respectively. This example will demonstrate how the introduction of basic automation can significantly reduce the operational risks.

Basic operation during fault conditions

When a permanent fault occurs the substation circuit breaker or recloser trips and recloses automatically while the sectionalisers count the supply interruptions, the first sectionaliser to reach its set SI count opens during the dead time of the recloser. This isolates the fault, and supply to the upstream portion of the feeder is restored automatically on the next reclose. The change of state in the sectionalisator is reported via a communications network to the control room to fulfil the FPI function. An operator opens the next downstream switch to isolate the faulty segment, reconfigures the protection in substation breakers if necessary and closes the normally-open point to restore power downstream of the faulty segment.

At this point, power is restored to the healthy parts of the network and it is possible for the operator to despatch the line crews to the faulted segment of the feeder to remove the fault. Once the entire feeder is healthy, the operator can open the normally-open point and close the sectionalisers to restore the network to the normal configuration.

Operational risks

Only the segments downstream of the fault are affected by the reaction time of the control room. It is therefore possible to
prioritise the segments in the feeder and plan the restoration times for each one. In practice the reaction time for the remainder of the feeder is still influenced by the same factors as in a telecontrolled feeder.

The impact of operators and the control room on the operational efficiency of this type of network is less than before.

Monitored sectionalisers can be used for fault passage indication. Fully featured sectionalisers offer improved fault detection and controller capabilities. This may reduce false indication issues when features such as inrush restraint and cold load pickup are used. Additional FPIs can be installed to improve network monitoring.

Similar to the telecontrolled switch network, communication failure can result in incorrect switching operations and an increase in the time taken to restore power.

Due to the sectionaliser logic, the feeder upstream from the fault is unaffected by communication problems. However, communications are required to sectionalise the downstream portion of the network and to control the normally-open point.

If a complete breakdown of communications is experienced it is possible for the control room to use customer calls to determine the affected parts of the feeder. In this way the maintenance crews can focus their effort on the first sectionaliser within the “complaints area”, open it, and then close the normally-open point.

Although not an ideal solution, in this case customers can be very helpful.

Advantages of sectionalising switchgear
- Relatively low initial cost of switchgear.
- Power is automatically restored to the upstream portion of the feeder.
- The importance of communications is slightly reduced although it is still required; Coordination between sectionalisers is easier.
- Improved fault detection capabilities are possible.
- FPI functionality is provided by the sectionalisers.

Disadvantages of sectionalising switchgear
- Faults affect all the customers connected to a feeder.
- Although improved, the level of automation is still low.
- Expensive communications infrastructure is still required.
- Operation is still dependent on the integrity of the communications network.
- All faults cause substation circuit breaker operation – this results in a shorter service life.
- Protection functionality is limited. Only one circuit breaker to detect high fault levels near the substation or low fault levels some distance away.

Evolving sophistication
The operational risks were substantially reduced with the introduction of sectionalisers in the feeder. However due to the limited protection features and the faults affecting the entire feeder, this solution may not be suitable for high priority customers – especially industrial customers. Automatic circuit reclosers (reclosers) are designed to overcome these problems.

Recloser systems
Today’s reclosers are capable of sophisticated protection, communication, automation and analytical functionality. With an abundance of processing power at their disposal, utilities have the flexibility to use the recloser as a stand-alone unit in a remote location, or to integrate several units into sophisticated substation automation systems. Whatever the application, the reclosers are flexible enough to evolve with the utility’s requirements. Reclosers monitor current, voltage, frequency and the power flow direction to protect the feeder. By coordinating the reclosers correctly, only the recloser that is closest to the fault will trip. This is important for the successful implementation of reclosers. A recloser can be programmed to automatically reclose when it tripped due to a fault. In this way, power is restored automatically in the event of a transient fault. If however the fault is permanent the recloser will trip again and remain open. It is possible to have up to a maximum of 4 trips to lockout.

Basic operation during fault conditions
It is possible to operate this type of network in either a “manual” mode where the operator has to perform the reconfiguration of the network, or in a “loop automation” mode where the reclosers perform all the task automatically.

In the “manual” mode the following actions are taken after the recloser immediately upstream of the fault automatically trips, recloses to lockout and remains open. An operator determines the location of the fault from the recloser status and/or additional FPIs; opens the next downstream recloser to isolate the faulty segment; reconfigures the protection settings in anticipation of reverse power flow; and closes the normally-open point to restore power downstream of the faulty segment.

Power is restored to the healthy parts of the network and it is possible for the operator to despatch the line crews to the faulted segment of the feeder. Once the entire feeder is healthy, the operator can open the normally-open point, reconfigure, and close the reclosers to restore the network to the normal configuration.

In the “loop automation” mode it is important to note that protection is the first and foremost function of the reclosers. A more sophisticated recloser is required to perform both protection and automation functions. In addition to these the reclosers have to measure power flow and voltage on both sides of the recloser.

To explain the basic operation of a loop automation scheme let’s first define the reclosers as follows:
- Feeder recloser (F) – Recloser closest to the substation;
- Tie (TIE) – The open point recloser where the two feeders meet. This is a normally-open point (NO); and
- Mid-point reclosers (MP) – All the reclosers positioned between the Feeder and Tie reclosers.
Each of these reclosers is programmed with a different set of rules when controlled by loop automation which can be simplified as follows: The feeder recloser trips when it loses supply; the mid-point recloser changes to the reverse power flow protection settings when it loses supply and the tie recloser closes when it detects that supply to one side of the network has been lost.

Loop automation uses time, voltage, power flow and these simple rules to isolate the fault and reconfigure the network without any communications or operator assistance. In a loop automation network, the following actions will take place when a fault occurs: The recloser immediately upstream of the fault automatically trips, recloses to lockout and remains open; reclosers downstream of the fault automatically change the protection settings in anticipation of power flowing in the opposite direction; and the normally-open tie recloser closes automatically. Due to the fault still being present, the recloser immediately downstream of the fault trips and locks out without reclosing.

This will automatically restore power to the healthy parts of the network. An operator can now despatch line crews to the faulted segment. It is also possible for the loop automation system to restore the original configuration when the fault is cleared.

Co-ordination of reclosers

To achieve current co-ordination on series reclosers, the operating time of each recloser must be faster than any upstream device and slower than any downstream device. That is, for the typical recloser network shown in Fig. 8 where a specific fault current is flowing through the network, "MP2" will trip more quickly than "MP1" and "MP1" will trip more quickly than "F". The instant the recloser closest to the fault trips, current through the other upstream reclosers reduce to load current and the sequence resets. This ensures that only the recloser immediately upstream of the fault will trip. A safe margin (approximately 200 ms) between operating times of successive devices must be maintained for all fault levels on the network being protected.

Pre-programmed inverse definite minimum time (IDMT) protection curves are used for phase and earth overcurrent protection. These curves allow close grading with substation protection relays and other protection devices.

Operational risks

In a manual system the segment downstream of the fault is affected by the reaction time of the control room. To assist the operator during feeder reconfiguration recloser systems are capable of automatically applying forward or reverse protection settings when power flow changes. In such a system the operator is not required to change the settings in all the reclosers.

A loop automation system does not require any operator intervention – all the operator has to do is despatch the line crews. The ON/OFF status and logs of reclosers are commonly used to determine the location of faults on feeders. With this inherent FPI functionality of the recloser false indication is eliminated.

Separate FPIs can be used in conjunction with the reclosers to assist the operators in determining the exact location of faults on long feeders.

Communications

Communications are not required at all in the loop automation scheme. However they may be desirable in order to monitor the status of the network at several key points to assist maintenance crews. In a manual recloser system the feeder upstream from the fault is unaffected by communication problems but communications are required to reconfigure the downstream portion of the network and to control the normally-open point.

Advantages of recloser systems

- Customers upstream from the fault are not affected at all.
- The Loop Automation scheme does not require communications.
- Power is restored quickly without any operator intervention, when the loop automation scheme is used.
- Advanced protection features are available.
- Multiple groups of settings are pre-set to ensure an effortless feeder reconfiguration when needed.
- Diagnostic tools are available with reclosers to assist in feeder analysis.
- The manual system still requires communications although the importance is reduced.
- With minimal effort the manual system can be upgraded to the loop automation system.

Disadvantages of recloser systems

The manual system may still require communications and it can affect the integrity of the feeder.

Evolving sophistication

Reclosers provide a very robust system, capable of protecting the feeder irrespective of many operational factors. The number of customers affected by permanent faults is minimised. However to further improve the feeder’s immunity to operational risks is very difficult and can be extremely expensive. To further improve these sophisticated networks, the focus shifts away from reducing operational risks to improving reliability of supply through feeder automation.

Feeder automation

A feeder automation network combines reclosers and sectionalisers in a feeder to provide grading on both current/time and number of operations. This is accomplished by introducing up to two sectionalisers in each zone protected by a recloser.

Basic operation during fault conditions

In a feeder automation network the reclosers protect the downstream portion of the feeder up to the next recloser. Similarly to the recloser network described earlier the recloser will trip and reclose in the presence of a fault and the sectionalisers count the through-faults similarly to the sectionalisers in the switchgear network described earlier. The difference is that if the fault occurs downstream of a sectionaliser, the sectionaliser closest to the fault will open before the recloser reaches lockout. Therefore, for this system to work correctly it is essential that the recloser is configured with four trips to lockout and the sectionalisers are configured with supply interrupt counters of three and two respectively.

For a feeder using one sectionaliser instead of two, the recloser is set to three trips to lockout and the supply interrupt counter in the sectionaliser is set to two (see Fig. 12).

Fig. 12 shows the importance of having a recloser dead time greater than the sectionaliser operating time. If this rule is ignored the sectionaliser contacts can open when the power is ON. This will result in the switch interrupting fault current, which can drastically shorten the operational life of the switch, and the recloser will trip to lockout.

The logic of a feeder automation network is best explained using timing diagrams for different fault locations.

Firstly, what happens when a fault occurs in Section 1? (Fig. 13).

The recloser “F” trips to lockout, remains open (OFF) and the sectionalisers do not change state.
When a fault occurs in section 2 (Fig. 14) the recloser trips and recloses twice before the sectionaliser “S1” opens to isolate the fault. The third reclose operation restores power up to “S1”. The recloser “F” sequence resets after the sequence reset time.

A fault in section 3 (Fig. 15) will cause the recloser to trip and reclose once before the sectionaliser “S2” opens to isolate the fault. Both sectionalisers count the interruptions. The second reclose restores power upstream of “S2”. The sequence resets in the recloser “F” and “S1” after the sequence reset time.

Advantages of feeder automation system

• Improved supply reliability when the segments are broken into smaller sections, therefore reducing the length of feeder that will be isolated in the event of a fault.
• Protection coordination is relatively easy.
• Flexible solutions are possible.
• Existing recloser or sectionaliser networks can be upgraded to incorporate full feeder automation with relative ease.
• The advantages of sectionalising switch and recloser networks are combined in feeder automation networks.
• Creative protection solutions are possible at relatively low cost.

With full directional capabilities the network will automatically reconfigure itself when the normally-open point is closed in the event of a fault.

Feeder automation in a looped network

When feeder automation is used in a looped network, it is necessary to consider using reclosers and sectionalisers with advanced capabilities such as directional protection and loop automation. With full directional capabilities the reclosers and sectionalisers are configured for protection with power flowing in both the forward and reverse directions. Protection in both directions is always active. This allows the utility to manually close the normally-open point in the event of a fault without having to reconfigure the other switchgear in the feeder. It is therefore possible to focus on the communications link to the normally-open point and by ensuring that it is reliable power restoration will always be possible. In a network using loop automation the switchgear controllers will automatically reconfigure the protection settings during fault conditions. Operation is very similar to that of a recloser-only loop automation scheme. The major difference is that reclosing is allowed to enable sectionalising, however the SI settings are reduced (see Fig. 16).

In the segment shown in Fig. 16 recloser “F” protects the segment during the normal configuration while recloser MP1 is protecting the segment when power is restored.

In a forward direction the following settings are used:

• “F” – forward protection and 4 trips to lockout.
• “S1” – forward detection and SI = 3.
• “S2” – forward detection and SI = 2.
• “MP1” – forward protection and 4 trips to lockout.

In a reverse direction the settings will change to:

• “F” is the closest recloser to the substation. A fault upstream of “F” will cause a loss of supply at the recloser and it will open to isolate the substation. If therefore does not change protection settings.
• “S1” – reverse detection and SI = 1.
• “S2” – reverse detection and SI = 2.
• “MP1” – reverse protection and 3 trips to lockout.

With only one sectionaliser per segment the settings are slightly different (Fig. 17).

In a forward direction the following settings are used:

• “F” – forward protection and 3 trips to lockout.
• “S1” – forward detection and SI = 2.
• “MP1” – forward protection and 3 trips to lockout.

In the reverse direction the settings will change to:

• “F” is the closest recloser to the substation. A fault upstream of “F” will cause a loss of supply at the recloser and it will open to isolate the substation. If therefore does not change protection settings.
• “S1” – reverse detection and SI = 1.
• “MP1” – reverse protection and 2 trips to lockout.

A feeder automation network provides a flexible solution to any protection challenge and is capable of evolving with the distribution requirements.
Due to the inherent FPI functionality of recloser and sectionalisers, separate FPIs are not included in the analysis where these devices are used.

The analysis also refers to two types of reclosers and sectionalisers – advanced and normal. Full directional protection capabilities, additional automation features (such as loop automation), and powerful analytical tools are available in the advanced products.

A network utilising sectionalisating switchgear monitored via dialup modem or radio provides the most cost effective solution in this example.

Depending on the type of terrain repeater stations may be required to transmit the radio signal around obstructions. Repeaters are typically shared between several distribution networks therefore affect the allocation of the cost. It is necessary to consider the cost of such an infrastructure when planning a distribution network.

The main cost disadvantage of the telecontrolled switch option is the communications network required for reliable operation. This “hidden” cost can increase the overall cost of the project substantially, often making it more expensive than sophisticated solutions. Although the feeder automation network requires the largest initial capital investment of all the benefit of such a network is easily realised when the costs of outages are compared.

Consider one outage of three hours in segment A. The loss in revenue is halved in a feeder automation network. In the feeder automation network this outage would result in a loss of \( \frac{1}{2} \) of the feeder revenue for three hours. The other networks loose \( \frac{1}{3} \) of the revenue for the three hours. The table below also shows how the impact of outages escalates when technical problems such as communications failures occur.

**Conclusion**

This paper describes a range of protection and segmentation options available in today’s technology-driven market. Although the options were explained using switchgear located on the main-line of the network, it is possible to apply the techniques to spur lines too. Existing networks can also keep up with future requirements by evolving to more sophisticated technology. In some cases it may be as easy as a firmware/software upgrade. Select your supplier carefully and ensure that the hardware platform is powerful and flexible enough to ensure sophistication where and when it is needed.

Contact Rick St John, Schneider Electric, Tel (011) 254-6400, rick@nulec.co.za

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**Table 4: Cost analysis breakdown.**

<table>
<thead>
<tr>
<th>Description</th>
<th>Multiplier</th>
<th>Tel Controlled</th>
<th>Sectionaliser</th>
<th>Recloser Manual</th>
<th>Recloser Automated</th>
<th>Feeder Automation</th>
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</thead>
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<td>Substation recloser</td>
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<td>6</td>
<td>0</td>
<td>0</td>
<td>5</td>
<td>30</td>
<td>5</td>
</tr>
<tr>
<td>Optical line covers (per km)</td>
<td>0.3</td>
<td>77.5</td>
<td>21.25</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Phone/Radio covers (per station)</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>5</td>
<td>5</td>
<td>0</td>
</tr>
<tr>
<td>Normalised cost</td>
<td>48.15</td>
<td>39</td>
<td>40</td>
<td>49</td>
<td>64</td>
<td>57%</td>
</tr>
<tr>
<td>Cost differential</td>
<td>-26%</td>
<td>-2%</td>
<td>-3%</td>
<td>0%</td>
<td>57%</td>
<td></td>
</tr>
</tbody>
</table>

**Feeder revenue at risk: 4 MW load per feeder**

The table below compares two scenarios. Firstly where the network was reconfigured successfully and secondly where the attempt to reconfigure the network failed due to a communications problem.

A dial-up or radio control network is assumed for both the sectionalising and manually controlled recloser networks. Communications are not required for the automated recloser and feeder automation networks and have therefore been removed from the analysis.

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**Fig. 18: Example network used in cost analysis.**

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**Fig. 17: Feeder automation with one sectionaliser.**