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Distribution System Reliability

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1. Motivation

- The main purpose of distribution systems is to provide electricity to customers to conduct the activities that require electricity. Assessment of the distribution system to determine the extent to which electricity is made available to the customers without interruptions provides a measure of system reliability.

- Reliability is defined as the ability of the system to provide electricity without interruptions, and resiliency is defined as the ability of the system to recover from extreme or unplanned events.

- The subject of system resiliency and associated measures are still evolving.

- The focus of the slide is on reliability, although resiliency has an impact on it.

1. Motivation

- The main motivation for reliability assessment is to analyze and improve system performance:
    - enhances customer satisfaction and satisfies regulatory requirements
    - provides information for maintenance scheduling, the basis for new or expanded system planning
    - determines performance-based rate making
- Various operation, maintenance, and design strategies can be used to enhance reliability. The reliability assessment therefore begins at the design and planning stages to build a new substation, to upgrade existing facilities, to add new feeders, and to identify poorer performing (weak) sections of the system. Operationally, the assessment will be needed to reconfigure the system for reduction in the customers affected, to add tie points to other feeders, or to develop postfault switching plan.
- Performance-based rate making in de or reregulated environments:
    - aids in forecasting utility's revenue
    - assists in quantifying the “quality” of power delivered to customers in evaluating the regulatory requirements specified by Public Utility Commissions (PUCs)
    - also useful in benchmarking the system performance in comparison to others.

1. Motivation

- Distribution System Performance & Reliability:
  - Overall performance: measured in terms of system losses and voltage profile
  - Reliability: measured with respect to probability of experiencing outages and to customer satisfaction.
- Outages: caused by failure of equipment due to bad quality, aging, human error, or extreme weather events. As all these causes have uncertainties associated with them, we rely extensively on probabilistic analysis to quantify system reliability.
- Customer satisfaction is measured in terms of the number of momentary and sustained interruptions, the duration of outages, the number of customers affected, and the number of customer complaints.
- Reliability can be improved by hardening or upgrading the entire system: not cost effective.
- A targeted approach to selectively harden the system will result in optimal results. Similarly, maintenance techniques can be enhanced to obtain optimal results.

2. Basic Definitions

- Various standardized indices are used for measuring reliability and associated computations. Definitions are given in this section to aid the readers in understanding the factors that affect the calculation of indices. Many of these definitions were taken directly from The Authoritative Dictionary of IEEE Standards Terms, 7th Edition and/or IEEE Standard 1366-2012.

a) **Connected Load:** Connected transformer kVA, peak load, or metered demand on the circuit or portion of circuit that is interrupted. When reporting, the report should state whether it is based on an annual peak or on a reporting period peak.

b) **Customer:** A metered electrical service point for which an active bill account is established at a specific location (e.g. premises).

c) **Customer Count:** The number of customers either served or interrupted depending on the usage.

d) **Forced Outage:** The state of a component when it is not available to perform its intended function due to an unplanned event directly associated with that component.

2. Basic Definitions

e) **Interrupting Device:** A device whose purpose is to interrupt the flow of power, usually in response to a fault. Restoration of service or disconnection of loads can be accomplished by manual, automatic, or motor-operated methods. Examples include transmission circuit breakers, feeder circuit breakers, line reclosers, line fuses, sectionalizers, and motor-operated switches.

f) **Interruption:** The loss of service to one or more customers connected to the distribution portion of the system. It is the result of one or more component outages, depending on the system configuration. Note that the outage of a component does not necessarily result in interruption.

g) **Interruption Duration:** The time from the initiation of an interruption to a customer until service has been restored to that customer. The process of restoration may require restoring service to small sections of the system until service has been restored to all customers. Each of these individual steps should be tracked, collecting the start time, end time, and the number of customers interrupted for each step.

2. Basic Definitions

h) **Interruptions Caused by Events Outside of the Distribution System:** Outages that occur on generation, transmission, substations, or customer facilities that result in the interruption of service to one or more customers. While this is generally a small portion of the number of interruption events, these interruptions can affect many customers and may last for an exceedingly long duration.

i) **Lockout:** The final operation of a recloser or circuit breaker to isolate a persistent fault or the state where all automatic reclosing has stopped. The current-carrying contacts of the overcurrent protecting device are locked open under these conditions.

j) **Loss of Service:** A complete loss of voltage on at least one normally energized conductor to one or more customers. This does not include any of the power quality issues such as sags, swells, impulses, and harmonics.

k) **Major Event:** An event that exceeds reasonable design and or operational limits of the electric power system. It includes at least one major event day (MED).

2. Basic Definitions

l) **Major Event Day:** A day in which the daily system average interruption duration index (SAIDI) exceeds a threshold value, TMED. For the purposes of calculating the daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than TMED are days on which the energy delivery system experienced stresses beyond that normally expected (such as severe weather). Activities that occur on MEDs should be separately analyzed and reported.

m) **Momentary Interruption:** A single operation of an interrupting device that results in a voltage zero. For example, two circuit breaker or recloser operations (each operation being an open followed by a close) that momentarily interrupt service to one or more customers is defined as two momentary interruptions.

n) **Momentary Interruption Event:** An interruption of duration limited to the period required to restore service by an interrupting device. Such switching operations must be completed within a specified time of five minutes or less. This definition includes all reclosing operations that occur within five minutes of the first interruption. For example, if a recloser or circuit breaker operates two, three, or four times and then holds (within five minutes of the first operation), those momentary interruptions shall be considered one momentary interruption event.

2. Basic Definitions

o) **Outage (Electric Power Systems):** The state of a component when it is not available to perform its intended function due to some event directly associated with that component. (Note: An outage may or may not cause an interruption of service to customers, depending on the system configuration. This definition derives from transmission and distribution applications and does not apply to generation outages.)

p) **Planned Interruption:** A loss of electric power that results when a component is deliberately taken out of service at a selected time, usually for the purposes of construction, preventative maintenance, or repair. (Note: This derives from transmission and distribution applications and does not apply to generation interruptions. The key test to determine if an interruption should be classified as a planned or unplanned interruption is as follows: if it is possible to defer the interruption, the interruption is a planned interruption; otherwise, the interruption is an unplanned interruption.)

q) **Planned Outage:** The state of a component when it is not available to perform its intended function due to a planned event directly associated with that component.

r) **Reporting Period**: The time period from which interruption data is to be included in reliability index calculations. The beginning and end dates and times should be clearly indicated. All events that begin within the indicated time period should be included. A consistent reporting period should be used when comparing the performance of different distribution systems (typically one calendar year) or when comparing the performance of a single distribution system over an extended period of time. The reporting period is assumed to be one year unless otherwise stated.

2. Basic Definitions

s) **Step Restoration:** A process of restoring interrupted customers downstream from the interrupting device/component in stages over time.

t) **Sustained Interruption:** Any interruption not classified as a part of a momentary event. That is, any interruption that lasts more than five minutes.

u) **Total Number of Customers Served:** The average number of customers served during the reporting period. If a different customer total is used, it must be clearly defined within the report.

v) **Unplanned Interruption:** An interruption caused by an unplanned outage.

3. Reliability Indices

- *IEEE Standard 1366* (published in 1998) with 12 most significant indices, provides a guide for utilities to assess the reliability of distribution systems.The indices are categorized into system-level and customer-level indices.

a) System-level indices
  - Frequency of outages (SAIFI, CAIFI, ASIFI)
  - Duration of outages (SAIDI, CAIDI, ASIDI)
  - Momentary outages (MAIFI, $MAIFI_E$)

b) Customer-level indices
  - Frequency (CAIFI, $CEMI_n$, $CEMSMI_n$)
  - Duration (CTAIDI)

- The indices can be classified based on sustained or momentary outages. They can also be classified based on duration and frequency indices. Ultimately, most of these are measures of availability of the system under study or investigation. Unfortunately, there is no one measure that can describe the reliability of the distribution system completely because of its complex nature.

3.1 Basic Parameters

The following parameters specify the data needed to calculate the indices for the reporting period:

i	An interruption event
r_i	Restoration time for each interruption event
$\boldsymbol{I_S}$	Total number of sustained interruption events
K	Number of interruptions experienced by an individual customer
CI	Customers interrupted
CMI	Customer minutes interrupted
CN	Total number of distinct customers who have experienced a sustained interruption
$\mathrm{CN}_{(k \geq n)}$	Total number of customers who experienced n or more sustained Interruptions
$\mathrm{CN}_{(t \geq S)}$	Total number of customers who have experienced a sustained interruption of more than S hours
$\mathrm{CN}_{(t \geq T)}$	Total number of customers who have experienced more than T hours of sustained interruptions

3.1 Basic Parameters

$\mathrm{CNT}_{(k\geq n)}$	Total number of customers who have experienced n or more combined sustained and momentary interruption events
IM_i	Number of momentary interruptions
IM_E	Number of momentary interruption events
N_i	Number of interrupted customers for each sustained interruption event
N_{mi}	Number of interrupted customers for each momentary interruption event
N_T	Total number of customers served for the area
$\boldsymbol{L}_i$	Connected kVA load interrupted for each interruption event
L_T	Total connected kVA load served
T_{MED}	Threshold value for the MED identification

3.2 Sustained Interruption Indices

- Service interruptions lasting more than five minutes are classified as sustained interruptions.
- Interruptions shorter than five minutes are considered part of a momentary event.
- The demarcation of five minutes is based on the industry's recognition that many temporary faults can be resolved through reclosing operations within one minute.
- A permanent fault, which causes sustained interruption, needs physical inspections and rarely can be cleared in less than five minutes.
- The industry has established this demarcation to differentiate between sustained and momentary interruptions.

3.2 Sustained Interruption Indices

1) System Average Interruption Frequency Index (SAIFI)

This index gives the average number of times a customer experienced a sustained interruption over a predefined period.

$$\text{SAIFI} = \frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers Served}}$$

$$= \frac{\Sigma_i N_i}{N_T} = \frac{\text{CI}}{N_T}$$

2) System Average Interruption Duration Index (SAIDI)

This index gives the total average duration of interruption experienced by a customer during a predefined period. It is typically measured in customer minutes of interruption.

$$\text{SAIDI} = \frac{\text{Total Customer Minutes of Interruption}}{\text{Total Number of Customers Served}}$$

$$= \frac{\Sigma_i r_i N_i}{N_T} = \frac{\text{CMI}}{N_T}$$

3.2 Sustained Interruption Indices

3) Customer Average Interruption Duration Index (CAIDI)

This index gives the average time needed to restore service.

$$\text{CAIDI} \quad = \frac{\text{Total Customer Minutes of Interruption}}{\text{Total Number of Customers Interrupted}}$$

$$= \frac{\sum_i \ r_i N_l}{\text{CI}} = \frac{\text{CMI}}{\text{CI}}$$

Also,

$$\text{CAIDI} = \frac{\text{SAIDI}}{\text{SAIFI}}$$

4) Customer Total Average Interruption Duration Index (CTAIDI)

This index gives the total average time that customers who experienced at least an interruption were without power. This index is similar to CAIDI except that customers with multiple interruptions are counted only once.

$$\text{CTAIDI} \quad = \frac{\text{Total Customer Minutes of Interruption}}{\text{Total Number of Distinct Customers Interrupted}}$$

$$= \frac{\Sigma_i r_i N_i}{\text{CN}} = \frac{\text{CMI}}{\text{CN}}$$

3.2 Sustained Interruption Indices

5) Customer Average Interruption Frequency Index (CAIFI)

This index gives the average frequency of sustained interruptions for those customers experiencing sustained interruptions. The customer is counted once regardless of the number of times interrupted for this calculation.

$$\text{CAIFI} = \frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Distinct Customers Interrupted}}$$

$$= \frac{\sum_i N_i}{\text{CN}} = \frac{CI}{\text{CN}}$$

6) Average Service Availability Index (ASAI)

This index gives the percentage of time that a customer has received power during the defined reporting period.

$$\text{ASAI} = \frac{\text{Customer Hours of Service Availability}}{\text{Customer Hours of Service Demand}}$$

$$= \frac{N_T \times \text{ Number of Hours } - \sum_i \frac{r_i N_i}{60}}{N_T \times \text{ Number of Hours}}$$

If the reporting period is one year, the number of hours are 8760 for normal years and 8784 for a leap year.

3.2 Sustained Interruption Indices

7) Customers Experiencing Multiple Interruptions ($CEMI_n$)

This index gives the fraction of individual customers experiencing more than n sustained interruptions.

$$\mathrm{CEMI}_n = \frac{\begin{array}{c}\text{Total Number of Customers that Experienced } n \\ \text{or More Sustained Interruptions}\end{array}}{\text{Total Number of Customers Served}}$$

$$= \frac{\mathrm{CN}_{(k \geq n)}}{N_T}$$

8) Customers Experiencing Long Interruption Durations (CELID)

This index gives the fraction of individual customers who experience interruptions with durations longer than or equal to a given time. The time is either the duration of a single interruption (S) or the total amount of time (T) that a customer has been interrupted during the reporting period. For the single interruption duration, we get

$$\mathrm{CELID}_S = \frac{\begin{array}{c}\text{Total Number of Customers that Experienced} \\ \text{an Interruption of } S \text{ or More Hours}\end{array}}{\text{Total Number of Customers Served}}$$

$$= \frac{\mathrm{CN}_{(t \geq S)}}{N_T}$$

3.2 Sustained Interruption Indices

And for the total interruption duration, we get;

$$\mathrm{CELID}_T = \frac{\text{Total Number of Customers that Experienced total Interruption Duration of } T \text{ or More Hours}}{\text{Total Number of Customers Served}}$$

$$= \frac{\mathrm{CN}_{(t \geq T)}}{N_T}$$

3.3 Load Based Indices

- These Indices use load interrupted instead of customers affected.They are useful for measuring system performance in areas that serve relatively few customers and have large concentrations of load, such as industrial and commercial customers.

1) **Average System Interruption Frequency Index (A SIFI)**

This index gives the average number of times the system experienced sustained interruptions over a predefined period.

$$\text{ASIFI} = \frac{\text{Total Connected kVA of Load Interrupted}}{\text{Total Connected kVA Served}} = \frac{\sum_i L_i}{L_T}$$

2) **Average System Interruption Duration Index (ASIDI)**

The index gives the average duration of system load interruption based on connected load.

$$\text{ASIDI} = \frac{\text{Total kVA duration of Load Interrupted}}{\text{Total Connected kVA Served}} = \frac{\sum_i r_i L_i}{L_T}$$

3.4 Momentary Interruption Indices

- These indices are based on the momentary interruptions experienced by the customers.

1) **Momentary Average Interruption Frequency Index (MAIFI)**

This index gives the average frequency of momentary interruptions experienced by customers over a duration.

$$\text{MAIFI} = \frac{\text{Total Number of Customer Momentary Interuptions}}{\text{Total Number of Customers Served}} = \frac{\sum_i \ \text{IM}_i N_{mi}}{N_T}$$

2) **The Momentary Average Interruption Event Frequency Index (MAIFI_E)**

This index gives the average frequency of momentary interruption events. It does not include the events immediately preceding a sustained interruption.

$$\text{MAIFI}_E = \frac{\text{Total Number of Customer Momentary Interuptions Events}}{\text{Total Number of Customers Served}}$$

$$= \frac{\sum_i \ \text{IM}_E N_{mi}}{N_T}$$

3.4 Momentary Interruption Indices

3) **Customers Experiencing Multiple Sustained Interruption and Momentary Interruption Events Index ($CEMSMI_n$)**

This index is the ratio of individual customers experiencing n or more of both sustained interruptions and momentary interruption events to the total customers served. It is useful in identifying customer issues that are hidden in averages.

$$\mathrm{CEMSMI}_n = \frac{\text{Total Number of Customers Experiening } n \text{ or more Interruptions}}{\text{Total Number of Customers Served}}$$

$$= \frac{\mathrm{CNT}_{(k \geq n)}}{N_T}$$

3.5 Sustained Interruption Example

- Consider a feeder serving 1000 customers as shown in the Figure with several single-phase laterals connected to it through fuses.
- Protecting scheme:
  - The recloser opens whenever there is a fault downstream.
  - The recloser closes after a short delay and opens again if the fault is not cleared.
  - It will reclose multiple times based on the selected settings for number of reclosing operations and will lock out after that if the fault is still there.
  - The fuse opens if the fault is downstream of the fuse, or the recloser opens if the fault is on the main feeder.
  - The breaker opens if there is a fault anywhere downstream or it but upstream of the recloser. It follows an operation procedure similar to recloser.
  - Opening of the breaker causes an interruption to all the customers served from this feeder.

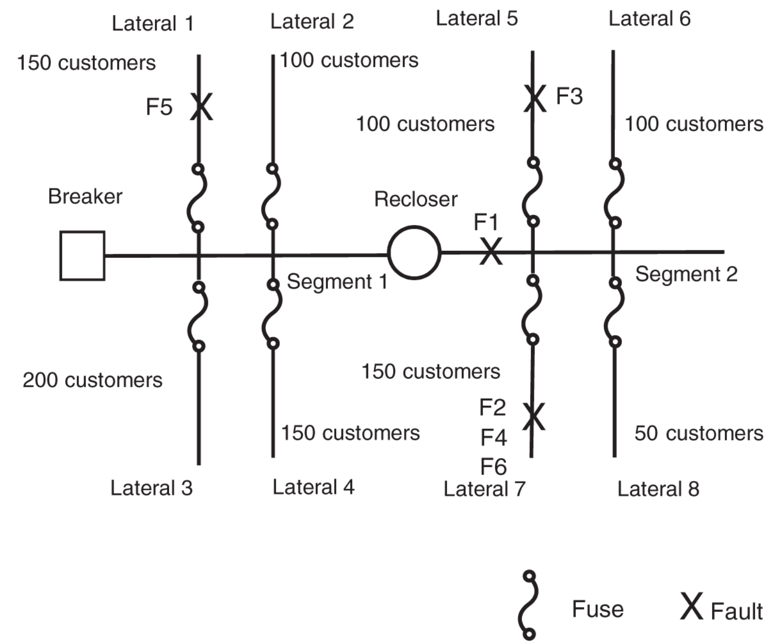

Figure. An example distribution feeder.

3.5 Sustained Interruption Example

Date	Time Off	Time On	No. of Customers	Load (kVA)	Interruption Type	Location
March 20	20:18:30	22:20:00	400	800	S	F1
April 9	15:15:20	15:28:40	150	300	S	F2
May 12	08:25:25	08:28:36	1000	2200	M	Unknown
June 11	04:39:40	04:50:10	100	100	S	F3
July 8	23:45:15	00:15:00	150	350	S	F4
Aug 19	15:20:45	15:45:00	150	250	S	F5
Sept 22	18:22:23	18:42:53	150	320	S	F6

Table. Log of interruptions in the system

- A part of the outages logged in the system is provided in the table.
- Note that the outage on 12 May has a total duration of 3 minutes and 11 seconds, which is a momentary interruption according to the cutoff time of 5 minutes.
- Since this outage interrupted all the customers, it must have been due to operation of the breaker or could be due to an event in the transmission systems.
- Note that 400 customers experienced at least one sustained interruption, and 150 customers (connected to lateral with F2, F4, and F6 faults) experienced four sustained interruptions and total interruption of longer than three hours.

3.5 Sustained Interruption Example

- Various indices can be computed based on the data in this table.

$$SAIFI = \frac{400+150+100+150+150+150}{1000} = 1.1$$

$$SAIDI = \frac{(400 \text{ x } 121.5)+(150 \text{ x } 13.33)+(100 \text{ x } 10.5)+(150 \text{ x } 44.75)+(150 \text{ x } 24.25)+(150 \text{ x } 20.5)}{1000}$$

$$= 65.07 \text{ Min}$$

$$CAIDI = \frac{SAIDI}{SAIFI} = \frac{65.07}{1.1} = 59.15 \text{ Min}$$

$$CTAIDI = \frac{(400 \text{ x } 121.5)+(150 \text{ x } 13.33)+(100 \text{ x } 10.5)+(150 \text{ x } 44.75)+(150 \text{ x } 24.25)+(150 \text{ x } 20.5)}{550}$$

$$= 130.14 \text{ Min}$$

$$CAIFI = \frac{400+150+100+150+150+150}{550} = 2$$

$$ASAI = 1 - \frac{\begin{array}{c}((400 \times 121.5) + (150 \times 13.33) + (100 \times 10.5) \\ +(150 \times 44.75) + (100 \times 24.25) + (150 \times 20.5))\end{array}}{8760 \times 1000 \times 60}$$

$$= 0.99988$$

$$ASIFI = \frac{800 + 300 + 220 + 300 + 200 + 300}{2200} = 1.06$$

$$ASIDI = \frac{\begin{array}{c}(800 \times 121.5) + (300 \times 13.33) + (220 \times 10.5) \\ +(300 \times 44.75) + (200 \times 24.25) + (300 \times 20.5)\end{array}}{2200}$$

$$= 58.15 \text{ minutes}$$

3.5 Sustained Interruption Example

- Note that 150 customers experienced four sustained interruptions with a total duration of 200 minutes and 5 seconds, which gives $CN_{(k \geq 4)}$ and $CN_{(t \geq 3)}$ equal to 150.
- Also, the longest interruption of 121 minutes and 30 seconds due to F1 affected 400 customers, which gives $CN_{(s \geq 2)}$ equal to 400.
- If we count the total interruption including momentary and sustained, 250 customers experienced three or more interruptions, which gives $CNT_{(k \geq 3)}$. We can use this information to compute the additional indices.

$$\mathrm{CEMI}_4 = \frac{150}{1000} = 0.15$$

$$\mathrm{CELID}_{S(2)} = \frac{400}{1000} = 0.4$$

$$\mathrm{CELID}_{T(3)} = \frac{150}{1000} = 0.15$$

$$\mathrm{CEMSMI}_5 = \frac{150}{1000} = 0.15$$

$$\mathrm{CEMSMI}_3 = \frac{250}{1000} = 0.25$$

3.6 Momentary Interruption Example

- The table shows a sample of momentary interruptions recorded for the system.
- The recorded data shows a total of 6600 momentary interruptions (IM_i) and 3600 momentary events $(IM)_E$
- The momentary interruption indices are computed as:

Date	Time	Device	No. of operations	No. of operations to lockout	No. of customers interrupted
4 October	08:18:22	Breaker	1	3	1000
15 October	14:13:21	Recloser	3	4	400
16 November	05:21:40	Breaker	2	3	1000
25 November	18:45:37	Recloser	2	4	400
8 December	02:18:45	Recloser	1	4	400
18 December	19:10:06	Recloser	3	4	400

Table. Log of momentary interruptions in the system

$$\mathrm{MAIFI} = \frac{1000 + 400 \times 3 + 1000 \times 2 + 400 \times 2 + 400 + 400 \times 3}{1000} = 6.6$$

$$\mathrm{MAIFI}_E = \frac{1000 + 400 + 1000 + 400 + 400 + 1200}{1000} = 3.6$$

4. Major Event Day Classification

- Distribution systems are designed for handling outages that happen under normal operation.
- Certain unforeseen events, mainly due to extreme weather, can push the system to the limit by causing numerous outages. Such events skew the reliability performance of the system and thus are excluded from the calculations of reliability indices.
- A Major Event Day (MED) is defined as a day in which the daily system *SAIDI* exceeds threshold value, T_{MED}.
- Using *SAIDI* as the index because:
  - It has led to consistent results regardless of the utility size.
  - It is a good indicator of operational and design stress on the system.
- For calculating the daily system SAIDI, any interruption that spans multiple days is accrued to the day on which the interruption begins.
- T_{MED} value is calculated at the end of each reporting period (typically 1 year) for use during the next reporting period.

4. Major Event Day Classification

- The process called "Beta Method" is used to identify MEDs
- The major purpose of Beta Method is to allow major events to be studied separately from daily operation and in the process to better reveal trends in daily operation that would be hidden by the large statistical effect of major events.
- Specific steps of the Beta Method are:
  1. Gather daily SAIDI values for five sequential years until the end of the reporting period. If less than five years of data are available, use all the available historical data, as less than five years may not yield accurate results.
  2. Exclude days with zero SAIDI from the dataset.
  3. Compute the natural logarithm (*ln*) of SAIDI for all the days in the dataset.
  4. Calculate the average (α) of the logarithms of the data set.
  5. Calculate the standard deviation (β) of the logarithms of the data set.
  6. Compute the value of *k* using the following equation:

$$\ln(T_{MED}) = \alpha + k\beta$$

or,

$$T_{MED} = e^{(\alpha + k\beta)}$$

4. Major Event Day Classification

7. The Table provides probabilities and the expected number of MEDs for different values of k in the Beta Method. The value of k determines the threshold for identifying MEDs based on the daily system SAIDI. However, there is no analytical method for selecting the allowed number of MEDs per year.

8. To address this, a recommended value of k, namely k = 2.5, has been established based on consensus among members of the IEEE Power and Energy Society's Distribution Reliability Working Group

9. Any day with daily SAIDI greater than the threshold value T_{MED} that occurs during the subsequent reporting period is classified as a MED.

Table. Probability of exceeding T_{MED} as a function of k

k	Probability	MEDs/yr
1	0.15866	57.9
2	0.02275	8.3
2.4	0.00822	3.0
2.5	0.00621	2.3
3	0.00135	0.5
6	9.9×10^{-10}	3.6×10^{-7}

5. Causes of Outages

- Each piece of equipment in a distribution system has a certain probability of failing.
- When first installed, a piece of equipment can fail due to poor manufacturing, damage during shipping, or improper installation.
- Healthy equipment can fail due to high currents, extreme voltages, animals, and severe weather.
- Sometimes equipment may fail due to chronological age, chemical decomposition, contamination, and mechanical wear.
- Failures in distribution systems can be categorized into three groups: **intrinsic factors**, **external factors**, and **human factors**.
- **Intrinsic factors:** age of equipment, manufacturing defects in equipment, and the size of conductors.
- **External factors:** trees, birds/animals, wind, lightning, and icing.
- **Human factors:** vehicular accidents, accidents by utility or contractor work crew, and vandalism.

5. Causes of Outages

- Since distribution system overhead lines are highly exposed to the atmosphere, external factors are the major causes of damages or failures. Intrinsic factors, on their own, generally do not endanger the reliability of such lines. Their effect can be seen only when they are combined with some other factors.
- For example, a very old small conductor would not break down or burn down by itself, but if lightning strikes lines with such conductors, probability of its break down or burn down is much higher than that of a new conductor under the same situation.

5.1. Trees

Trees are among the major factors that affect the reliability of an overhead distribution line. Trees can cause failure of such lines in the following ways:

- Overhead conductors can be damaged when struck by a falling branch of tree.
- Wind can blow a tree branch into overhead conductors, resulting in two wires contacting each other.
- A growing branch of a nearby tree can push two phase conductors together resulting in a two-phase fault.
- During regular tree trimming, a tree branch can be accidentally dropped on the overhead line.
- Ice accumulation on tree branches can cause limbs to break off and fall on the conductors.

Tree Trimming for Overhead Line Reliability:

- Tree trimming means periodic pruning of vegetation near power lines, which is the best possible solution to avoid overhead line failures caused by trees.
- Trimming is done every 2-6 years in most distribution systems.
- Selective trimming focuses on trees causing more customer interruptions, which can reduce operating and maintenance costs.
- Some utilities trim only main feeder trunks, not lateral branches.
- Tree trimming should always be performed by a trained crew to ensure safety and direct regrowth away from the conductor location.

5.2. Lightning

- Lightning is a transient, high-current electric discharge caused by the breakdown of air due to large electric fields.
- Lightning can occur within a cloud, from a cloud to the surrounding air, between adjacent clouds, and from a cloud to the ground.
- Intracloud, cloud-to-air, cloud-to-cloud, and cloud-to-ground lightning are the different types of lightning discharges.
- Cloud-to-ground lightning is of particular concern due to its threat to power systems.
- Lightning can affect power systems in two ways:
  - **Direct strokes:** Lightning directly strikes the power system. Although the incidents of direct strokes are very few, they are very dangerous for the system.
  - **Indirect strokes:** Most of the lightning strikes are of this type. They do not strike the power system directly, instead they strike some nearby objects such as a tall building or a tree. In this case, a traveling voltage wave is induced, which is less severe than the direct strokes.

5.2. Lightning

- Lightning can cause severe damage to overhead lines, which cannot be fully avoided but can be reduced by careful application of shield wires and surge arresters.

- Surge arresters should be inspected for any manufacturing defects, and also, very old arresters should be replaced by new ones to prevent any damage caused by lightning.

- The level of damage caused by lightning depends on some other factors also. For example, lightning could be more destructive for a very small and very old conductor compared to a big and new conductor.

5.3. Wind

- The probability of equipment failure increases rapidly with increasing wind speed because the pressure exerted on trees and poles is proportional to the square of the wind speed.

- Wind can lead to supply interruptions in the following ways:

  - Wind can cause a tree branch to touch two phase conductors together, resulting in a fault.

  - Wind induces several types of conductor motions – swinging, galloping, and aeolian vibrations. If the swing amplitude is high, phase conductors could touch each other. Conductor galloping is the phenomenon when conductor starts moving up and down harmonically due to wind. Aeolian vibrations are generated by the air turbulence on the downwind side of the conductor. All these conductor motions are not good from the reliability point of view.

- To mitigate interruptions caused by wind:

  - In highly windy areas, maintain a larger spacing between conductors.

  - Use twisted pair conductors to prevent the mentioned conductor motions.

5.4. Icing

- Ice storms occur when supercooled rain freezes on contact with tree branches and overhead conductors and forms a layer of ice, which can cause outages in multiple ways:
  - Heavy accumulation of ice on tree branches can cause them to break off and fall on the conductors.
  - Ice places heavy physical load on conductors and support structures.
  - Combination of ice and wind can result in sagging of conductor. The possibility of sagging is more when the conductor is of very small size. When ice breaks off, it can cause the conductor to jump into the conductor located above it.
- To prevent failures caused by ice storms:
  - Overhead conductors and supporting structures should have high strength to withstand the physical load imposed by ice.
  - Areas prone to ice storms should consider using larger conductors to improve resilience against ice-related issues.

5.5. Animals/Birds

- Animals and birds can cause harm to an overhead distribution line in several ways. Following are a few possibilities that may result in customer interruptions:
  - Squirrels cause faults by bridging grounded equipment with the phase conductor.
  - Raptors and roosting birds cause faults by bridging conductors with their wings.
  - Woodpeckers cause damage to utility poles by pecking holes in them.
  - Large animals, such as cattle, horse, and bear, can also do physical damage to utility poles, making the system more prone to future outages.
- To avoid failures caused by various animals and birds, several remedies can be implemented:
  - Install plastic animal guards on bushings and insulators to prevent squirrels from simultaneously touching the tank and phase conductors.
  - Use anti-roosting devices on attractive perches to prevent birds from roosting.
  - Use steel or concrete poles instead of wooden poles to avoid problems caused by woodpeckers.
  - Use barricades near wooden poles to reduce the problems caused by large animals.

5.6. Vehicular Traffic

- Vehicular accidents can lead to damage in distribution systems:
  - Collisions between fast-moving vehicles and distribution poles can result in pole damage, conductor sagging or swinging, and equipment damage.
  - Pad-mounted equipment are also vulnerable to vehicular accidents.
- Methods to prevent damage caused by vehicular accidents:
  - Use concrete barriers and concrete poles to reduce the frequency of automobile collisions.
  - Concrete barriers should be employed to protect pad-mounted equipment from vehicular accidents.

5.7. Age of Components

- Each component of a distribution feeder has its own probability of failure.
- It is often assumed that the performance of distribution system components deteriorates when they reach approximately 30 years of age.
- However, the age of a component alone does not create reliability issues. Its effects become apparent when combined with other factors such as conductor size, wind velocity, and lightning intensity in the area.
- Components that are around 30 years old and contribute to reliability problems should be replaced with new ones on feeders experiencing such issues.

5.8. Conductor Size

- Conductor size, when considered alone, does not cause any reliability problem.
- Similar to “age,” its effects can also be seen when combined with some other factors.
- For example, in high wind velocity areas, the swinging amplitude of small conductors will be high compared to big conductors.

6. Outage Recording

- Utilities record daily outages in the service territory. The recorded data include time, duration, location, number of customers affected, and the possible cause of the outage.
- The Table shows the number of outages and their causes recorded for a period of two years from January 2003 to December 2004 for 66 feeders with a total length of approximately 1000 km in the distribution system of a city in Kansas.
- The data show that trees/vegetation and animals/wildlife caused 53.47% of outages followed by equipment failure and unknown.
- Environmental factors, which include lightning, extreme wind, trees, animals, ice storm, and debris, caused a total of 1290 outages, which is 61% of all the outages.
- A significant number of outages are reported as unknown or other causes. The cause of the outage is recorded by the field crew based on inspection and any circumstantial evidence at the site of the outage. Sometimes, the crew is not able to determine the cause, and they declare it as unknown.

Cause	Number of outages	Percentage
Customer request	0	0.00
Equipment failed	251	11.80
Overload	41	1.93
Trees/vegetation	634	29.79
Public damage	25	1.17
Customer problem	0	0.00
Animals/wildlife	504	23.68
Other	141	6.63
Lightning	131	6.16
Extreme wind	8	0.38
Ice storm	13	0.61
Trees outside right of way	0	0.00
Debris, nature/weather	0	0.00
Unknown	208	9.77
Company damaged	0	0.00
Procedural error	1	0.05
Load transfer	0	0.00
Safety/hazard	0	0.00
Load shed	0	0.00
Maintenance	171	8.04
Total	2128	100.00

Table. Causes and number of outages in a service territory in Kansas in 2003 and 2004.

6. Outage Recording

Seasonal variation in the number of outages:

- The figure showing outages occurring in each month during the study period.
- The number of outages is higher during the summer months (June, July, August, and September). The main reason for this is due to thunderstorms and windy conditions during the summer months.
- The graph also shows a large number of outages for January 2004. Most of these outages were due to trees, which fell on the feeders during icy conditions caused by winter storms.
- Although spring and fall that have quieter weather will lower the probability of outages, most of the outages during these seasons are caused by squirrels.
- Nice weather promotes higher animal activity. Also, the end of winter and the end of summer coincide with the birth of new litter of squirrels, which increases the probability of them causing outages.

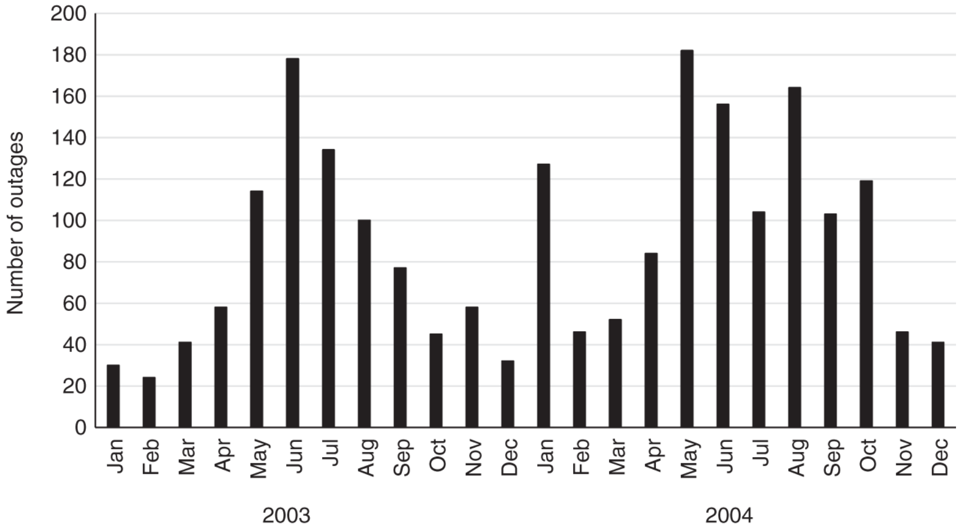

Figure. Monthly outages in a service territory in Kansas.

7. Predictive Reliability Assessment

- The data-based approaches for reliability evaluation are able to provide an assessment of the system performance during a period in the past.
- These approaches are not capable of predicting the expected reliability in the future.
- Predictive reliability assessment requires the integration of **component failure models**, **network topology**, and **reduction techniques**.
- Next Slides will focus on exploring various aspects of predictive reliability assessment.

7. 1 Component Failure Models

- Every Components in distribution systems are designed to operate without failure throughout their lifetime.
- However, failures can occur due to intrinsic defects or external causes.
- The failure rate of components is typically higher in the early stages of deployment due to manufacturing defects, shipping damage, or incorrect installation.
- After the break-in period, components are expected to perform well during their expected life, but the failure rate may increase towards the end of their life due to aging.
- The failure of components can be modeled using a hazard function or failure rate.
- The bathtub curve is a commonly used representation of component reliability, showing a high failure rate in the early and late stages, and a constant failure rate during the useful life.

7. 1 Component Failure Models

- Hazard rate or failure rate of a component measures the probability of failure at time t, given that the component has been functioning until that time.
- The lifetime of the component can be treated as a random variable.
- Failures can be represented by a probability density function (PDF) *f(t).*
- The PDF describes the likelihood of the component failing at different time points.
- The cumulative probability distribution function (CDF) *F(t)* gives the probability of the component failing before or at time *t*.
- An expression for hazard function *h(t)* is given by:

$$h(t) = \frac{f(t)}{1 - F(t)}$$

- Exponential function is commonly used for modeling constant failure rate.

7. 1 Component Failure Models

- In exponential modeling, the probability of a component failing at time t, given that it is working at time t, is independent of t.

- The exponential probability distribution function provides expressions for the probability density function (PDF) *f(t)* and the cumulative probability distribution function (CDF) *F(t)*.

$$f(t) = \lambda e^{-\lambda t}$$
$$F(t) = 1 - e^{-\lambda t}$$

- On substitution on equation of *h(t),* we get,

$$h(t) = \lambda$$

7. 2 Network Reduction

- Power distribution systems consist of components connected in series or parallel configurations.
- In a series connection, all components must be functional for electricity delivery.
- In a parallel connection, at least one functional component is required for electricity delivery.

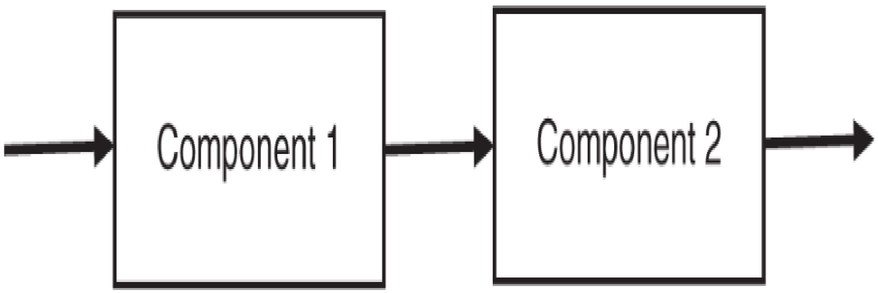

Figure. Two components connected in series

- If all components in a parallel connection become unavailable, it will result in a disruption of service.
- Consider that two components with probability of availability P_1 and P_2 are connected in series as shown in the figure.

7. 2 Network Reduction

- P_1 and P_2 can be computed from the failure rate and mean time to repair (MTTR).

- So, for a duration of one year, with λ_1 as the annual failure rate, and R_1 as the MTTR of component 1, P_1 for a year is

$$P_1 = \frac{8760 - \lambda_1 R_1}{8760}$$

And,

$$Q_1 = 1 - P_1$$

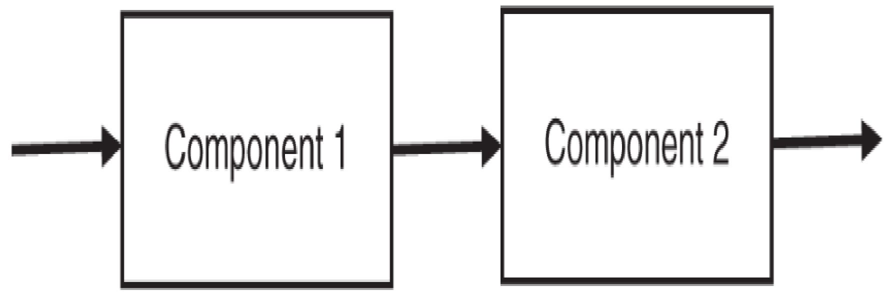

Figure. Two components connected in series

where Q_1 is the annual probability of unavailability of component 1. Hence, the combined probability of availability of both components 1 and 2 is

$$P_{\text{series}} = P_1 P_2$$

7. 2 Network Reduction

- If there are *n* components in series, we can generalize the equation to find probability of all of them being available, or

$$P_{\text{series}} = \prod_{i=1}^{n} P_i$$

$$Q_{\text{series}} = 1 - P_{\text{series}}$$

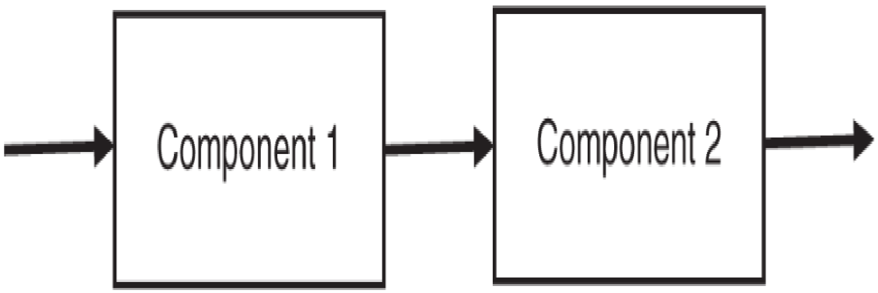

Figure. Two components connected in series

which is,

$$Q_{\text{parallel}} = Q_1 Q_2$$

And,

$$P_{\text{parallel}} = 1 - Q_{\text{parallel}}$$

- If there are *n* components in parallel, the equation can be generalized to determine the probability of unavailability of all of them, or

$$Q_{\text{parallel}} = \prod_{i=1}^{n} Q_i$$

Example

- Consider a network of six components connected as shown in Figure (a). Various steps required to reduce this network for reliability evaluation are shown in Figure (b).
- The given probabilities of availability of these components are $P_1 = 0.9$, $P_2 = 0.8$, $P_3 = 0.7$, $P_4 = 0.6$, $P_5 = 0.5$, and $P_6 = 0.4$. We can determine the probability of series connected components 1–2 and 4–5.

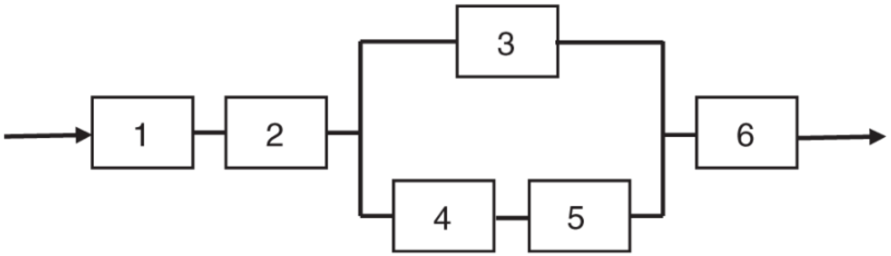

Figure (a). A network of six components

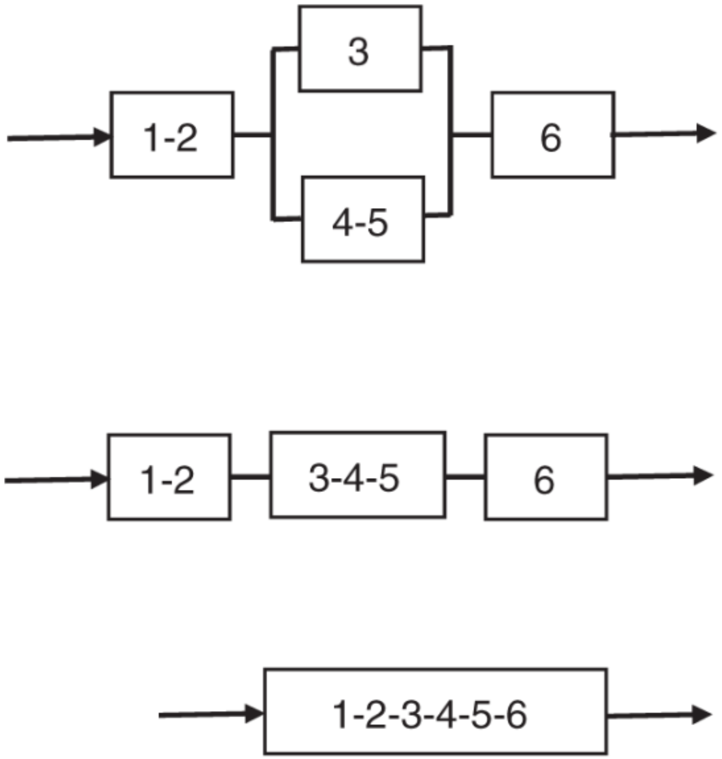

Fig (b). Steps for network reduction

Example

$$P_{1-2} = P_1 \times P_2 = 0.9 \times 0.8 = 0.72$$

$$P_{4-5} = P_4 \times P_5 = 0.6 \times 0.5 = 0.30$$

And,

$$Q_{4-5} = 1 - P_{4-5} = 1 - 0.30 = 0.70$$

Also,

$$Q_3 = 1 - P_3 = 1 - 0.70 = 0.30$$

Therefore,

$$Q_{3-4-5} = Q_3 \times Q_{4-5} = 0.30 \times 0.70 = 0.2$$

Or,

$$P_{3-4-5} = 1 - Q_{3-4-5} = 1 - 0.21 = 0.79$$

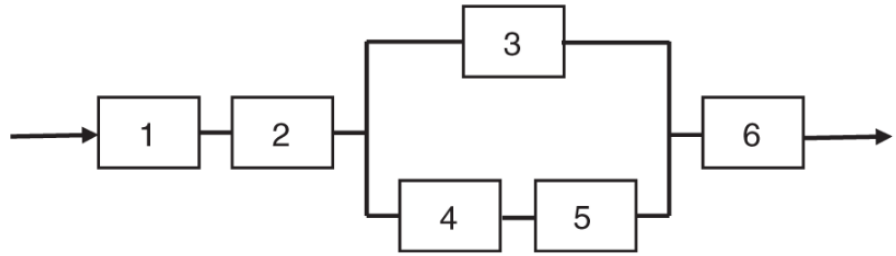

Figure (a). A network of six components

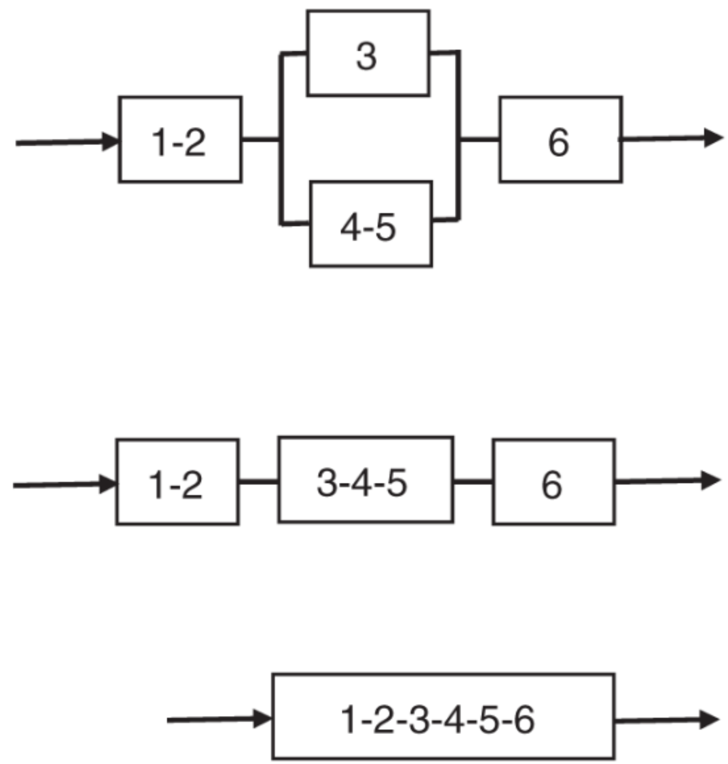

Fig (b). Steps for network reduction

Example

Now, we find the probability of continuity of the whole network, which is

$$P_{\text{Network}} = P_{1-2} \times P_{3-4-5} \times P_6$$
$$= 0.72 \times 0.79 \times 0.40$$
$$= 0.22752$$

Note: Network reduction works well for simple systems but becomes very tedious for large systems. Therefore, it is not suitable for large complex systems with many components.

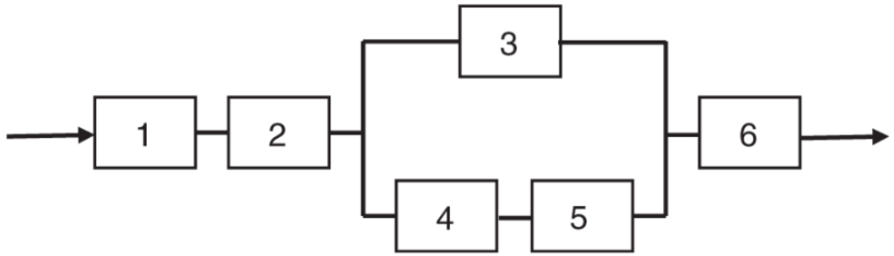

Figure (a). A network of six components

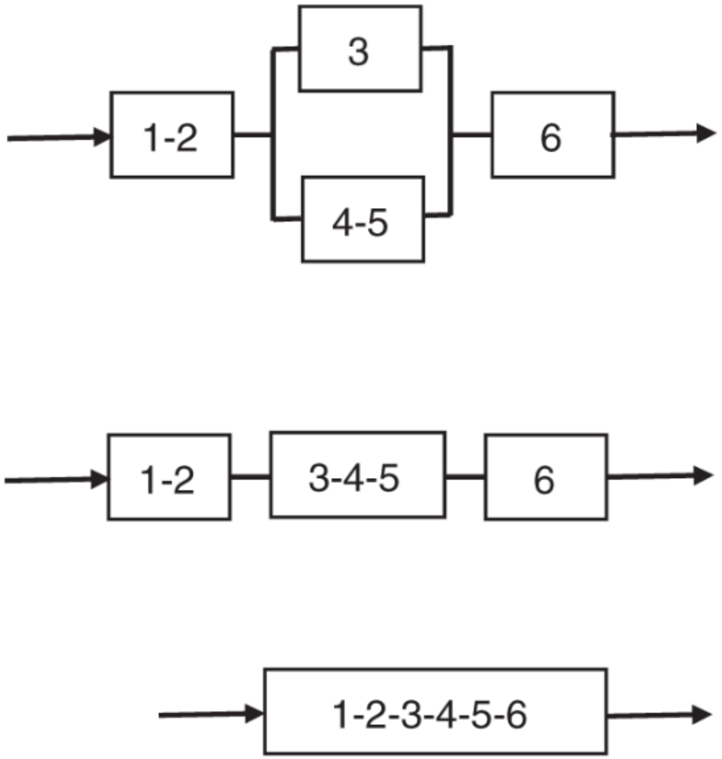

Fig (b). Steps for network reduction

7. 3 Markov Modeling

- Markov modeling is a popular approach for reliability assessment of power systems.
- Markov modeling is based on the Markov process, which involves defining different states of the system.
- The states represent different operating states of the system, including fully operational and failure states.
- Transitions between states occur randomly and are determined by the probabilities of component failure and repair.
- Failure and repair probabilities in Markov modeling follow exponential distributions, resulting in constant failure rate (λ) and constant repair rate (μ).
- An important property of the Markov process is its memoryless nature, meaning that future probabilities only depend on the present state and not on the past.

7. 3 Markov Modeling

- if we consider that the system is in state *i* at time *t*, we can write an expression for transition probabilities at time *(t + Δt)* for a small *Δt*

$$P[X(t+\Delta t)=j \mid X(t)=i]=p_{ij}(\Delta t)$$

and

$$P[X(t+\Delta t)=i \mid X(t)=i]=p_{ii}(\Delta t)$$

where $p_{ij}(\Delta t)$ is the probability that the state will change to j, and $p_{ii}(\Delta t)$ is the probability that the state will remain i at time $(t+\Delta t)$. We further define transition intensities, which are

$$q_{ij}=\lim_{\Delta t\to 0}\frac{p_{ij}(\Delta t)}{\Delta t}, i\neq j$$

And,

$$q_{ii}=\lim_{\Delta t\to 0}\frac{1-p_{ii}(\Delta t)}{\Delta t}$$

7. 3 Markov Modeling

Since the sum of probabilities of being in any state is 1 , we can write

$$p_{ii}(\Delta t) + \sum_{j \neq i} p_{ij}(\Delta t) = 1$$

which gives,

$$q_{ii} = \sum_{j \neq i} q_{ij}$$

Further, we can define a transition intensity matrix $\boldsymbol{A}$

$$\boldsymbol{A} = \begin{bmatrix} -\boldsymbol{q}_{11} & \boldsymbol{q}_{12} & \boldsymbol{q}_{13} & \cdots & \cdots & \cdots \\ \boldsymbol{q}_{21} & -\boldsymbol{q}_{22} & \boldsymbol{q}_{23} & \cdots & \cdots & \cdots \\ \vdots & \vdots & \vdots & \vdots & \vdots & \vdots \\ \boldsymbol{q}_{i1} & \boldsymbol{q}_{i2} & \boldsymbol{q}_{i3} & \cdots & -\boldsymbol{q}_{ii} & \cdots \\ \vdots & \vdots & \vdots & \vdots & \vdots & \vdots \end{bmatrix}$$

Let *P[X(t) = i]* be $p_i(t)$, which is the unconditional probability of being in state *i* at time *t*. If we define as the time derivative of $p_i(t)$, we can write an equation in matrix form for all the states of the system.

7. 3 Markov Modeling

$$\dot{\boldsymbol{p}}(t) = \boldsymbol{p}(t)\boldsymbol{A}$$

Note that $\dot{\boldsymbol{p}}(t)$ and $\boldsymbol{p}(t)$ are row vectors,

$$\boldsymbol{p}(\boldsymbol{t}) = [p_1(t) \quad p_2(t) \quad p_3(t) \quad \cdots \quad p_i(t) \quad \cdots]$$

and

$$\boldsymbol{p}(\boldsymbol{t}) = [p_1(t) \quad p_2(t) \quad p_3(t) \quad \cdots \quad p_i(t) \quad \cdots]$$

- Differential equation can be solved to find probabilities of being in different states as a function of time, given the initial probabilities or ***p**(0).*
- For state probabilities in the long run, we let t → ∞ and . The above equation reduces to N ordinary linear equations for a system with N states.
- However, these equations are dependent, and thus, the determinant of A is zero. Thus, to solve this equation, we remove one of the equations and replace it by

$$\sum_{i=1}^{N} p_i = 1$$

or the probabilities of states must sum to 1 .

Example

- In a distribution system, we can use the Markov process by defining the states representing failure of a component, such as the section of a feeder. The failures and repairs of components are represented by exponential probability distribution functions giving constant failure and repair rates.

- Consider the system shown in page 23. To simplify, we consider only the failures of Segment 1 and Segment 2. Thus, as shown in the Figure, the system will have three states, which are system fully operational (State 1), Segment 1 failed (State 2), and Segment 2 failed (State 3).

- It is assumed that once a segment has failed, no additional failures will take place in the system until repairs on the failed segment are completed. Segment 1 is 1-mile long and Segment 2 is 2-miles long. The failure rates are 0.1 faults per mile per year, and the MTTR is three hours.

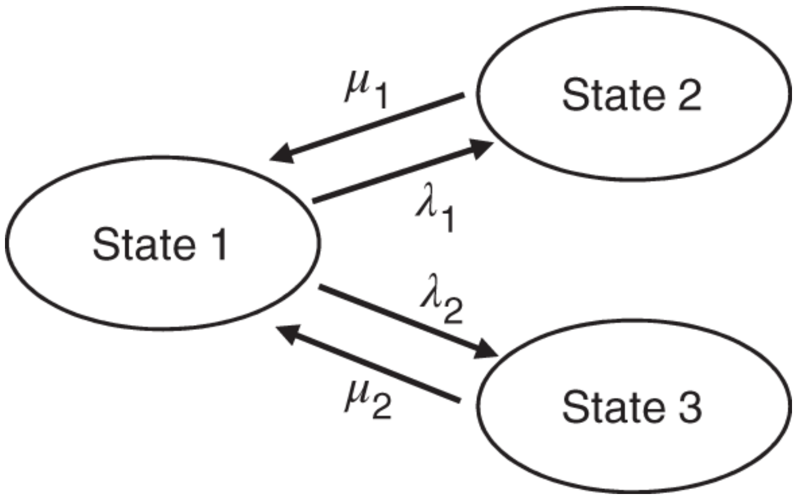

Figure. State transition diagram for the system of Figure 9.1 for outages on Segment 1 and Segment 2.

Example

- From the given data, we can determine the following values for the Markov model:

$$\lambda_1 = 0.1 \times 1 \text{ mile} = 0.1/\text{year or } 0.00001142/\text{hour}$$

$$\lambda_2 = 0.1 \times 2 \text{ miles} = 0.2/\text{year or } 0.00002284/\text{hour}$$

$$\mu_1 = \frac{1}{3} \text{ or } 0.3333/\text{hour (MTTR} = 3 \text{ hours)}$$

$$\mu_2 = \frac{1}{3} \text{ or } 0.3333/\text{hour (MTTR} = 3 \text{ hours)}$$

- The A matrix for the for the system is

$$\begin{bmatrix} -(\lambda_1 + \lambda_2) & \lambda_1 & \lambda_2 \\ \mu_1 & -\mu_1 & 0 \\ \mu_2 & 0 & -\mu_2 \end{bmatrix}$$

- Now, using Eq. (9.37) for steady state, we get:

$$[0 \quad 0 \quad 0] = [p_1 \quad p_2 \quad p_3] \begin{bmatrix} -(\lambda_1 + \lambda_2) & \lambda_1 & \lambda_2 \\ \mu_1 & -\mu_1 & 0 \\ \mu_2 & 0 & -\mu_2 \end{bmatrix}$$

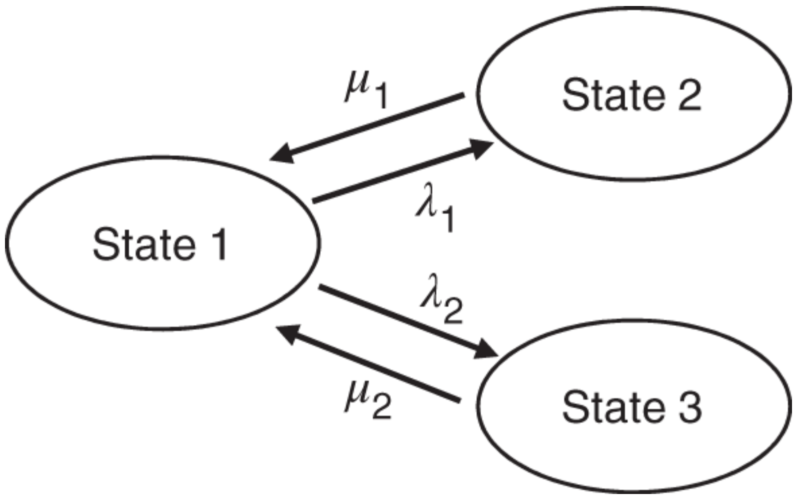

Figure. State transition diagram for the system of Figure 9.1 for outages on Segment 1 and Segment 2.

Example

- Delete the first column of the matrix and replace it by 1s to represent p1 + p2 + p3 = 1:

$$[1 \quad 0 \quad 0] = [p_1 \quad p_2 \quad p_3]\begin{bmatrix} 1 & \lambda_1 & \lambda_2 \\ 1 & -\mu_1 & 0 \\ 1 & 0 & -\mu_2 \end{bmatrix}$$

Or

$$[1 \quad 0 \quad 0] = [p_1 \quad p_2 \quad p_3]\begin{bmatrix} 1 & 0.00001142 & 0.00002284 \\ 1 & -0.3333 & 0 \\ 1 & 0 & -0.3333 \end{bmatrix}$$

- Solving the equation, we have p1 = 0.99989722, p2 = 0.0000342599, and p3 = 0.0000685198. As expected, the system spends most of the time in fully functional state.

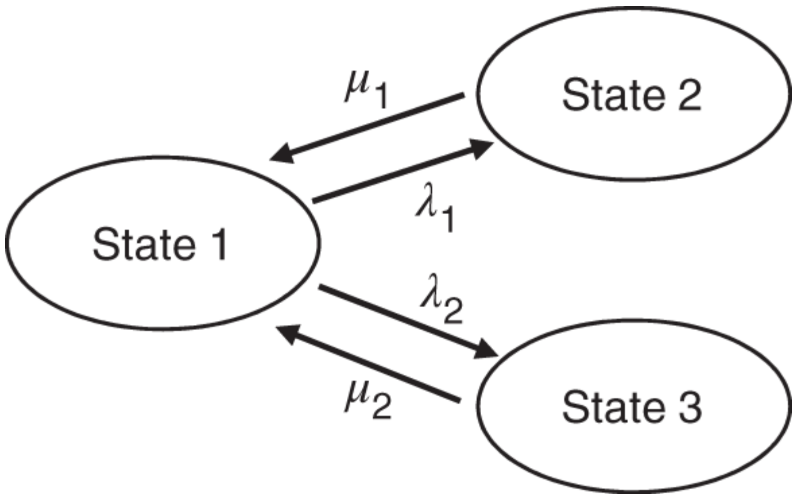

Figure. State transition diagram for the system of Figure 9.1 for outages on Segment 1 and Segment 2.

Example

- In the next step, we compute the total time the system would be in states of partial failure, which are 0.0000342599 × 8760 = 0.3 hour in State 2 and 0.0000685198 × 8760 = 0.6 hour in State 3.

- Further, we compute the customer minutes of interruptions in these two states as follows:

  State 2: 0.3 × 1000 × 60 = 18000

  State 3: 0.6 × 400 × 60 = 14400

- Thus, we get a total CMI of 18 000 + 14 400 = 32 400.

- Therefore $\text{SAIDI} = \dfrac{32\,400}{1000} = 32.4 \text{ minutes}$

- If we expand the problem to include failures of all the laterals in addition to the main feeder, the system will have 11 states. Since distribution systems are typically much larger than the example we have considered, implementation of this method becomes very tedious.

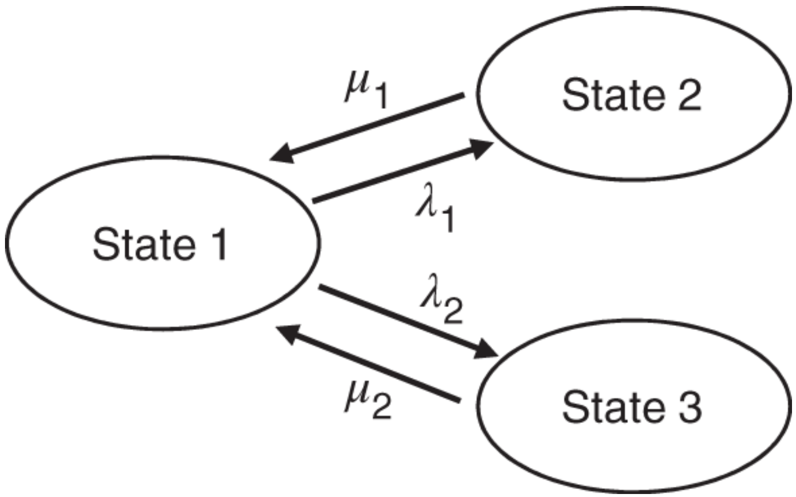

Figure. State transition diagram for the system of Figure 9.1 for outages on Segment 1 and Segment 2.

7.4 Failure Modes and Effects Analysis (FMEA)

- FMEA is an effective method for reliability analysis of radial distribution systems.
- The method incorporates system topology, device models, and system restoration models for system restoration.
- Capabilities include models for temporary and permanent faults, protection and switching including backup protection, isolation through protective device operation and sectionalizers, and full restoration through repair and partial restoration through switching.
- In the FMEA method, failure on every segment of the system is considered as a *Failure Mode*.
- Since each failure mode causes interruption of service to a part of the system, these interruptions are identified as Effects on the system reliability.

7.4.1 FMEA Method Assumptions

- Temporary and permanent faults are considered independent and mutually exclusive in the analysis.
- Each segment of the system is assumed to have a constant failure rate for faults, which follows an exponential probability distribution.
- The repair rate is also considered constant, implying that the probability of repair at time t after a failure has occurred follows an exponential probability distribution.
- The necessary data for the analysis include:
    - System topology: The configuration and arrangement of the distribution system.
    - Line segment failure rate or Mean Time Between Failures (MTBF): The average time between consecutive failures for a line segment.
    - Repair rate or Mean Time To Repair (MTTR): The average time required to repair a failed component or line segment.

7.4.2 FMEA Procedure

- Identify all failure modes and their system-wide effects.
- Determine the effects in terms of the number of customer outages and the duration of customer outages.
- Sum the effects of all failure modes to obtain the cumulative number of customer outages and the duration of customer outages over a specific period, such as a year.
- Compute system-wide indices such as SAIFI (System Average Interruption Frequency Index) and SAIDI (System Average Interruption Duration Index).

Example

- Again, consider the system shown in page 23. Additional data for the system are given in the Table.
- Segment 1 of the main feeder is from the breaker to the recloser, and Segment 2 is downstream of the recloser.

Component	Length (miles)	Failure rate (faults per mile per year)	Repair time (h)
Segment 1	1	0.1	3
Segment 2	2	0.1	3
Lateral 1	0.5	0.2	2
Lateral 2	1	0.2	2
Lateral 3	1	0.2	2
Lateral 4	1.5	0.2	2
Lateral 5	0.5	0.2	2
Lateral 6	1	0.2	2
Lateral 7	1	0.2	2
Lateral 8	0.5	0.2	2

Table. Data for the distribution system

Example

- We start the computations by considering failures on each component one by one and recording their effects. So, for Segment 1, the expected number of faults is 0.1, which is obtained by multiplying the failure rate per mile by the length in miles.

- Note that the failure rates are fractional numbers. These numbers are determined from the historical data for the specific utility. For example, if the utility has 2000 miles of laterals in its service territory, and 400 faults were recorded on these laterals, the failure rate comes out to be 0.2 faults per mile per year. This implies that not every section of the line will see a fault.

- However, for calculations, we use the expected number of faults. A fault on Segment 1 will interrupt service to all the customers, and they will have an expected interruption of 3 hours, which gives CMI of 100×180 or 18,000 minutes of interruption.

Example

- We can account for effects of faults on each component as shown in the Table.
- Further, we can compute the expected SAIFI and SAIDI for the system as shown below:

$$\text{SAIFI} = \frac{365}{1000} = 0.365$$

and

$$\text{SAIDI} = \frac{54{,}600}{1000} = 54.6 \text{ minutes}$$

Component	No. of faults per year	No. of customers affected	No. of customer interruptions	CMI
Segment 1	0.1	1000	100	18,000
Segment 2	0.2	400	80	14,400
Lateral 1	0.1	150	15	1800
Lateral 2	0.2	100	20	2400
Lateral 3	0.2	200	40	4800
Lateral 4	0.3	150	45	5400
Lateral 5	0.1	100	10	1200
Lateral 6	0.2	100	20	2400
Lateral 7	0.2	150	30	3600
Lateral 8	0.1	50	5	600
Total			365	54,600

Table. Computation of CMI

Example

- Now, consider the option of using the tie switch at the end of the feeder for restoration of power to the customers connected to Segment 2 whenever Segment 1 has a fault
- This is done by opening the recloser and closing the tie switch. Consider that this process takes four minutes. Hence, the 400 customers connected to Segment 2 will experience an interruption of only four minutes whenever a fault takes place in Segment 1.
- Since this interruption is less than five minutes, which is the cutoff between the momentary and sustained interruptions, the number of interruptions as well as the CMI for these customers will be removed from SAIFI and SAIDI calculations.
- Therefore, the total customer interruption reduces to 325, and CMI reduces to 47 400, which gives SAIFI of 0.325 and SAIDI of 47.4 minutes.
- Note that we are able to get information only on expected values of SAIFI and SAIDI, which are useful for comparison of different system topologies during the planning stages or for decisions relating to system upgrades.

7.5 Monte Carlo Simulation

- FMEA provides an assessment of system reliability based on estimated mean values of reliability indices.
- Detailed assessment requires Monte Carlo simulation, which can be time-consuming.
- In addition to knowing the mean value of failure rate (or time between failures) and time to repair (or repair rate), probability distribution of these two parameters is needed.
- While modeling failures with a fixed average rate and exponential probability distribution function is a good assumption, considering fixed average repair rate with exponential probability distribution function is strictly not true.
- Prior research shows that exponential probability distribution function provides good approximation. Also, the average failure rates and the associated probability distribution functions can change due to external conditions, such as storms.
- Since analysis with variable failure rates becomes very complex, we consider fixed failure rates.

7.5 Monte Carlo Simulation

Simulation process:

- The simulation begins by building failure scenarios for the system. Using a random generator, we determine the failure rate and the repair rate of each component from their respective probability distributions.
- Next we find the effects of each component's failure on the numbers of customers affected and the customer minutes of interruptions. The cumulative count of customer interruptions and customer minutes of interruptions provides the values of SAIFI and SAIDI.
- Repeat the process multiple times to get a distribution of SAIFI and SAIDI. The number of simulations is decided based on the desired results. The number of simulations is determined based on desired results and convergence to a stable value. For example, simulations can be continued until the mean of all simulations converges to a stable value.
- The results provide probability distribution of system indices from which the average and standard deviation as well as confidence levels can be computed.

7.5 Monte Carlo Simulation

- The size of the system has significant impacts on the results. Specifically, the standard deviation of SAIFI and SAIDI increases as the system size decreases. The spread of SAIDI is usually higher than that of SAIFI.
- Systems with higher failure rates or more faults have less standard deviation.
- As we zoom into the system, the spread of the reliability indices increases.
- The results provide annual performance standards for individual feeders or parts of the system.
- The results do not accurately forecast the system performance in the future.
- These results are valuable in relative comparison of feeders or systems against one another for planning improvements.

8. Regulation of Reliability

- Maintaining adequate level of reliability requires investments in system upgrades. However, there are trade-offs between cost and reliability.

- While the reliability of the bulk system, which includes transmission and generation, is regulated at the federal level in the United States, electric distribution is regulated at the state level.

- As reported, 35 states out of 50 states and District of Columbia actively regulate distribution system reliability. Frequencies and durations are commonly used metrics to measure the overall system performance.

- Typically, frequencies and durations are used to measure the overall system performance.

- Some regulators require utilities to report reliabilities in a smaller region, such as a geographic area or feeder, and may require identification of circuits with worst reliability. If a utility serves both urban and rural customers, the regulators may ask for separate reports for urban and rural regions.

- Some regulators have included reliability performance in their revenue regulations. These regulations may include penalties only for not meeting the standards or also rewards for exceeding the performance.

8. Regulation of Reliability

Other examples include setting quality of service target without any penalty or rewards and reporting only without targets. While the targets set by regulators and utilities vary widely. Some examples of targets are listed below:

- SAIDI of the worst performing feeder exceeding system SAIDI by 300%.
- SAIDI of a feeder greater than four times the system SAIDI or in the top 10% for two consecutive years.
- More than 90% of the interrupted system restored in 36 hours for all events except extreme events, and more than 90% restored in 60 hours for extreme events.
- Customers experiencing more than six outages per year for three consecutive years or outages with total duration of more than 18 hours per year for three consecutive years.

Thank You!