Chapter 6
Distribution System Risk Impact and Resolution

Electric power is a fundamental need of nowadays society. Every activity of people daily lives, starting from getting up in the morning till going to bed at night, all require electricity. In addition, not just only people's daily lives are supported by electric power, an economic activity such as production, commerce, service business, etc. also depended on the availability, reliability and quality of electric power. The failure of distribution system which results in power outage discontinues all such activities. The exact quantification of distribution system failure impact is somehow difficult to achieve. This is due to that there are many considerations and dimensions involved in the evaluation process. The main consideration includes financial and social aspects. The impact in terms of financial seems to be the most common indicator employed for quantifying the impact of power system failure.

Previous chapter has dealt with the quantification of the possibility that the distribution feeder failure would occur. It was done by evaluating the feeder asset condition rating against the operational and environmental stressors. The failure possibility obtained is shown in the percentage of occurrence. The figure will then be turned into the monetary value for the sake of comparability. The methods of monetary cost quantification is proposed and examined in this chapter.

The intention of this thesis is to review the existing costing methodologies and employ them for quantifying the main cost components that would be considered during the investment project evaluation stage. Thus there are only two cost components being taken for evaluating the financial impact of distribution system failure: the outage cost and resolution cost. The outage cost is the loss in terms of money that stakeholders suffer in the case of power outage whereas the resolution cost is the money utility spends to correct or prevent the failure. In this thesis, however, the cost of corrective action, i.e. repair cost that utility has spent to restore the power to its customers, is considered as the outage cost due to its consequence from the failure of power distribution system. The quantification of each cost component is made on the estimation basis.

6.1 Chapter Overview

The chapter begins with the evaluation of outage costs. Two types of outage cost are discussed. That is the cost borne by utility when feeder failure occurs and the cost posed to customers at the time of power blackout. The methodology introduced to quantify the outage cost is the interrupted energy rate. The chapter then introduces the countermeasures to mitigate the outage occurrence as well as the methodologies to evaluate the cost of obtainment. The total financial impact which is the cost-benefit evaluation of investment candidates is discussed in the final section.

6.2 Power Outage Cost

As stated before, electricity is needed for daily life activities of people. The failure of distribution system that results in power outage discontinues all such activities which in turn create some costs to stakeholders. This section only attempts to determine the costs that occur on two main stakeholders: power utility and its customers who have direct impact from such outage. The others such as social and environment costs which are very difficult to quantify will not be addressed here in this thesis.

6.2.1 Customer Outage Cost

The distribution system failure causes the adverse impact to both utility and customer. The determination of utility financial impact is straight forward. It is simply obtained by computing the financial loss in terms of energy sales and the repair cost to restore the system. The customer's outage cost may be more complicated to quantify. The power outage can cause both direct and indirect damages to the customers. Loss of production and raw materials, inconvenience and damages to life and assets are its direct result. While other damages such as crimes, move of factories or offices as well as the cancellation of goods orders as a result of late deliveries can be indirectly caused. Impacts and outage cost should be estimated in monetary value, which however is not quite possible in practice. Estimating the impacts on raw materials damaged during an outage is possible whereas estimating the impacts on life is somehow not easy, for example. This is so because the perspective of each consumer on the impacts of outage differs accordingly to their objective of power usage. Consumer categories, power quantity, interrupted activities, duration and period of outages should thus be the criteria of cost estimation. The framework for power outage cost evaluation is shown in figure 6.1. The description of this framework is made in the following sections.

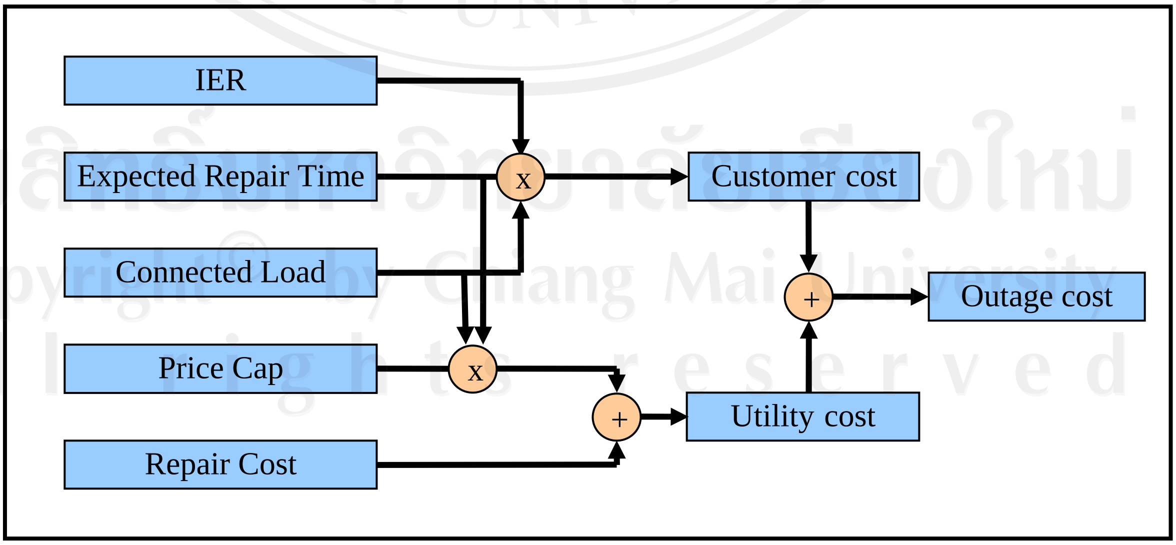

Figure 6.1 Outage cost to utility and its customers

6.2.1.1 Customer Damage Model

Customer interruption costs due to failure in electrical energy supply depend on many factors. There are several studies conducted to quantify the financial impacts caused by electric power outage [148, 149, 150, 151]. Most of them follow the methodology used in the value based planning for transmission and distribution system. In this concept, the customers have widely varying preferences for price and reliability and value-based planning is designed to match the level of investment in reliability with customers' reliability preferences [152].

The economic losses customers experience as a result of reliability and power quality problems can be described by what has been called a Customer Damage Function (CDF). In a CDF, the losses that customers face are expressed as a function of the magnitude of load interrupted, the duration of the interruption, and the season and time of day. The general form of CDF is:

$$\text{Loss (Baht/kW)} = f(\text{duration, season, time of day, notice}) \tag{6.1}$$

By employing this equation, the economic loss per interrupted kW can be thus predicted from the factors that influence outage costs.

There are two basic methods for estimating customer outage costs. The first is called *market-based*, with outage cost estimates driving from observations of actual customer behavior when presented with choices between services with different reliability levels. The second method is called *survey-based*, with outage cost estimates derived from statistical surveys of utility customers.

In Thailand, there was a study conducted by the Energy Research Institute of Chulalongkorn University in 2004 to estimate the outage costs in different areas throughout the country [153]. The study employed the survey-based method. The questionnaires had been developed so that they would suit the three main categories of consumers, which are consumers in industrial sector, business and service sector and household sector. The surveys were done by direct interview and internet survey.

It should be noted that, for demonstration purpose, the customer damage cost used in this thesis will be taken directly from the above mentioned study. This is due to the fact that it is only one source for this kind of information available for Thailand. Following discussion on the customer damage cost are summarized from above study.

In developing the customer damage model in the study, several types of damages are considered. For industrial and business and services customers for example, the damage costs of each customer include:

- Salary or work payment,
- Cost of loss of profit opportunity,
- Overtime payment,
- Cost of loss of raw material,
- Cost of re-starting the process, and
- Cost of damaged equipment.

The study is conducted based on above mentioned damage types.

From the study, the sectoral customer damage function is obtained first and then composite customer damage function can be computed using such the sectoral customer damage function. It thus provides a flexibility to calculate the financial damage cost either by customer type or composite damage in case that an exact load of each customer type can not be obtained. The customer damage costs in the Metropolitan Electricity Authority (MEA) area are summarized in table 6.1 and figure 6.2 below.

Table 6.1 Average customer damage cost of different customer types in MEA (Baht/$kW_{(peak)}$

Duration	**2 sec.**	**1 min.**	**30 min.**	**1 hr.**	**2 hr.**	**4 hr.**	**8 hr.**
Residential	0.000	0.487	5.361	11.454	25.346	53.184	114.031
Small general service	0.000	0.234	10.995	76.918	180.284	409.187	833.323
Medium general service	8.271	3.903	30.710	97.775	178.019	293.841	505.871
Large general service	0.299	0.977	10.239	29.549	70.417	100.581	182.753
Specific business	0.753	0.000	0.308	3.049	8.470	13.610	26.107
Government and non-profit organization	0.000	0.000	5.479	9.324	15.454	26.916	47.447

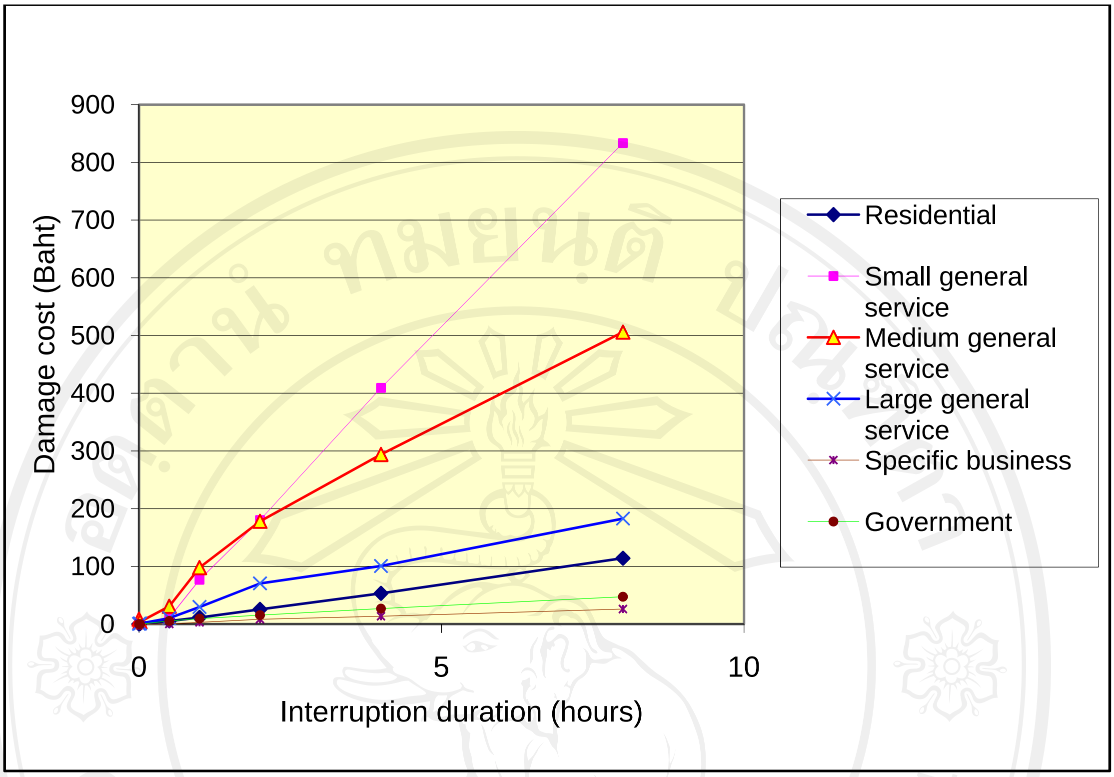

Figure 6.2 MEA customer damage cost based on customer type [153]

The composite customer damage function (CCDF), which represents the damage model of entire designated distribution area, i.e. MEA, can be computed using the equation

$$CCDF(t) = \sum_{i=1}^{n} c_i \times SCDF_i(t) \qquad \text{Baht/kW}_{\text{peak}} \qquad (6.2)$$

Where *i* is customer type,
n is a number of each customer type,
c_i is energy consumption of customer type *i*, and
$SCDF_i$ is sector customer damage function of customer type *i* which can be taken from table 6.1 above.

The *CCDF* in equation (6.2) is in the unit of Baht/kW_{peak}. However, it can be transformed into the unit of Baht/kW_{avg} to be used in outage cost evaluation by using equation 6.3

$$CCDF(t) = \sum_{i=1}^{n} \frac{c_i \times SCDF_i(t)}{LF_i} \qquad \text{Baht/kW}_{\text{avg}} \qquad (6.3)$$

where LF*i* is load factor of customer type *i*.

It should be noted the *CCDF*, which is in the unit of Baht/kW$_{avg}$, is the function of interruption duration, and it is written as *CCDF*(t). With the above equations, the *CCDF*s in MEA area can be calculated. If it needs to consider the outage cost of all the customers, the *CCDF* can also be obtained using the above equations. Table 6.2 illustrates average composite customer damage models in Baht/kW$_{avg}$ for MEA and PEA distribution area and whole Thailand.

Table 6.2 Average composite customer damage models (Baht/kW$_{avg}$)

Duration	**2 s**	**1 m**	**30 m**	**1 hr.**	**2 hr.**	**4 hr.**	**8 hr.**
MEA	3.033	1.944	19.020	65.996	136.717	245.184	458.956
PEA	8.533	13.131	37.661	62.794	105.610	208.010	374.720
All customers	6.452	8.905	30.587	63.881	117.097	221.618	405.735

The composite customer damage models are then used with electricity interruption statistics to calculate the outage cost of the area.

6.2.1.2 Interrupted Energy Rate

However, if specific area or certain feeder where information on interruption duration and lost load are available are of interest, the outage cost known as *Interrupted Energy Rate* (*IER*) or *Value of Lost Load* (*VOLL*) can be evaluated from the customer damage model, illustrated above and the actual interruption statistics. Using either *SCDF* or *CCDF* shown in table 6.1 or 6.2 and interruption statistic in interested area, the *IER* (Baht/kWh) can be calculated as per equations 6.4.

$$IER = \frac{Interruption\,Cost}{Energy\,Not\,Supplied} = \frac{ECOST}{EENS} = \frac{\sum_{j=1}^{n} CCDF(t_j) \times P_j}{\sum_{j}^{n} P_j \times t_j} \qquad (6.4)$$

where *CCDF* is Composite Customer Damage Function,
t_j is Interruption Duration of j^{th} interruption,
P_j is Load loss of j^{th} interruption, and
n is A number of interruption.

From above mentioned study [153], the results of the IER for MEA and PEA distribution area and whole Thailand have been summarized in table 6.3.

Table 6.3 Composite customer outage cost in Thailand

	IER (Bath/kWh)
MEA	53.799
PEA	60.165
Thailand	60.348

Let consider a numerical example order to demonstrate the application the *IER* for evaluating customer outage cost. Suppose that there are total of 1,000kW residential customers connected to the section of feeder in MEA distribution area; and utility needs about 4 hours to correct the broken components and restore the power back to the customers. From figure 6.1, we learn that

$$\text{Customer outage cost} = IER \times EENS \tag{6.5}$$

And we also learn that

$$EENS = \text{Lost load} \times \text{interruption duration} \tag{6.6}$$

In this case, the lost load is 1,000 kW and interruption duration is 4 hours the *EENS* is then equal to 4,000 kWh. Since *IER* in MEA area is 53.799 Baht/kWh then the customer outage cost would be 215,916 Baht. This outage cost value represents only one outage event. In real situation, however, many failures with different duration could be expected to occur during the remaining years of distribution asset service life, so operational statistics is needed for the calculation. For example, if system average interruption duration (SAIDI) is available; it can be used as interruption duration seen by each customer in one year; and yearly damage cost can be obtained using *IER*.

6.2.2 Utility Damage Cost

The consequences of power outage not only impact the customers' interests but also produce the costs to utility. The direct impact is that utility loses money of energy sales as well as spends money to repair the faulted network. Not to mention the others like corporate images and credibility which very hard to quantify monetary value. This subsection, however, tries to propose means to quantify the monetary losses to utility.

There are two cost components occur to utility when power is cut: loss of unsold energy and cost of repair. Each of them can be simply computed as follows.

$$\text{Unsold energy cost} = \text{Unsold MW} \times \text{interruption duration} \times \text{Price cap} \tag{6.7}$$

where price cap is the difference between energy purchase and energy sales. Table 6.4 shows the price cap for each customer type in MEA service area. The price caps shown are calculated based on 230kV purchase rate. From above example, the unsold energy cost that occurs to MEA in peak period is 6,115.60 Baht.

Table 6.4 Price cap for each customer type in MEA
(Source: MEA)

Customer Type	Size (kW)	Sale Rate		Price Cap	
		On peak	Off peak	On peak	Off peak
Residential		3.6246	1.1914	1.5289	0.1011
Small business	< 30	3.6246	1.1914	1.5289	0.1011
Medium business	30 – 99	2.6950	1.1914	0.5993	0.1011
Large business	> 999	2.6950	1.1914	0.5993	0.1011

The second component is the repair cost which can be estimated by equation (6.9).

$$\text{Repair cost} = \text{Material cost} + \text{Direct labor cost} + \text{Overhead charge} \qquad (6.9)$$

The idea for estimating this repair cost will be further investigated in the later section.

6.3 Cost Estimation for Utility Investment

To resolve the risk of distribution system failure, utility have to spend some money. Depending to the resolution that utility is going to choose

6.3.1 Work Breakdown Structure

A work breakdown structure (WBS) is a product-oriented family tree, composed of hardware, software, services, data, facilities, testing and everything else resulting from a system engineering process [154]. Whenever an organization has a large project to manage, whether developing a new power plant or organizing a big conference where several hundred people participating the event, breaking down the effort into manageable parts is the first step.

The Military Handbook MIL-HDBK-XI 1 [155] presents guidelines for preparing, understanding, and presenting a WBS for military projects. This handbook’s primary objective is to achieve a consistent application of WBS. The information it contains is intended to provide guidance to contractors and direction to government project managers. This guidance is appropriate for use with any WBS developed at any phase: concept exploration, program definition and risk reduction, engineering and manufacturing development or production, during the acquisition process.

The WBS is also the foundation for project planning and control. It is the connecting point for work and cost estimates, schedule information, actual work effort/cost expenditures, and accountability. It must exist before the project manager can plan these related and vital aspects of the project, and they all must be planned before the project manager will be able to measure progress and variance from plan. In order to perform this vital function, the WBS is at its core a hierarchy of deliverables or tangible outcomes.

In the distribution system project implementation, the WBS can be used for defining work packages, developing and tracking the cost and schedule for the project. The work is broken down into tasks (and subtasks), each of which has technical scope, resources to be used, costs and schedule as well as the assignment of responsible person. The general framework applied for power distribution system project can be demonstratively depicted in figure 6.3.

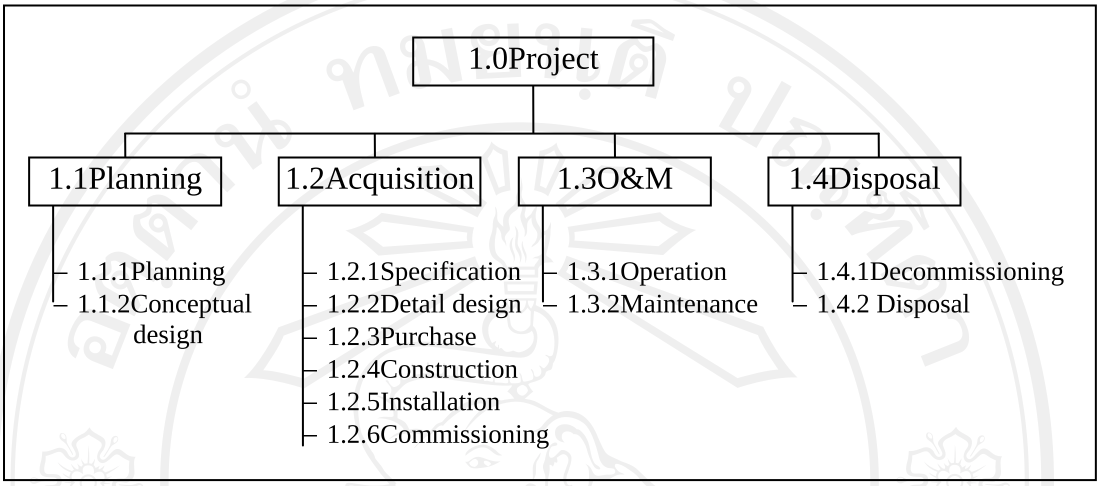

Figure 6.3 WBS for power distribution system project

Table 6.5 A typical example WBS of pole installation work.

WBS

Task name: Pole installation
Scope: installing 12 m concrete pole on ordinary ground

Material:

Code	Description	Quantity
5625-668-12100	Concrete pole 12m	1
5620-643-00100	Cement	10
5610-641-00100	Rough sand	0.5

Manpower:

Position	Number
Worker	2
Technician	1
Crane Operator	1

Machine:

Machine & Tool	Number
Mobile crane	1

Duration: 2 hrs.

Responsible person: Somsak

When investigating further into a certain task, *pole installation* work (subtask of *installation* task under *acquisition*) for example, work scope, resources to be used, costs, schedule and responsible person which will be later used to assist determining associated costs must be defined. Table 6.5 illustrates a typical example WBS of pole installation work.

6.3.2 Using WBS to Estimate Project Costs

The WBS assists project manager in measuring cost. By breaking the total work package into successively smaller entities, manager can verify that all work identified to the WBS actually contributes to the project objectives. Using WBS elements to plan the work serves as the basis for estimating and scheduling resource requirements.

Using the WBS to help with cost estimating facilitates project management [156]. The WBS provides a systematic approach to cost estimating that helps ensure that relevant costs are not omitted. An estimate based on WBS elements helps project manager to plan, coordinate, and control the various project activities that utility and the contractors are conducting. The WBS also provides a common framework for tracking the evolution of estimates (e.g., conceptual estimates, preliminary design estimates, and detailed design estimates). The WBS can also provide a framework for life cycle cost analysis. As periodic project cost estimates are developed, each succeeding estimate is made in an attempt to forecast more accurately the project's total cost. Basically, the estimates may be organized in two ways: by WBS element or by code of accounts. Both support utility's on-going efforts in preparing budgets and evaluating contractor performance.

WBS also assists project budgeting. In general, funds management involves periodic comparison of actual costs with time-phased budgets, analysis of variances, and follow-up corrective action (as required). When WBS elements and the supporting work are scheduled, a solid base for time-phased budgets is ready-made. Assignment of planned resource cost estimates to scheduled activities and summarization of each WBS element by time period results in a time-phased project/contract budget, which becomes the performance measurement baseline.

To estimate the project cost, once the work package is broken down into small entities, cost can be allocated to these entities and summarized up to form the total project cost. The pole installation work for example, cost can be allocated to any materials, machines and resource person used in this task by computing from unit rate and quantity of resources.

In the light of this research study, the cost components that are considered for project cost estimation consist of mainly two components: material and labor costs. Table 6.6 and 6.7 illustrate materials and labor costs for obtaining the main equipment installed in distribution network. This is of course calculated based on the work breakdown structure.

Table 6.6 Typical cost components of overhead distribution feeder
(Source: MEA)

Category	Components	Unit	Material Unit Cost	Manpower Unit Cost
Pole structure				
	Pole	set	8,104.00	8,376.80
	Crossarm	pc.	1,110.94	798.00
	Guy	set	8,600.00	4,788.00
	Fittings	set	298.05	532.0
Conductor assembly				
	Conductor	m	181.70	113.20
	Insulator	pc.	136.44	638.00
	Splice	set	113.18	266.00
Lightning protection				
	OHGW	m	43.22	1.60
	LA	set	2,400.00	1,064.00
Switches				
	Fuse cutout	set	5,815.27	2,128.00
	Switches	set	3,592.82	2,660.00

Table 6.7 Typical cost components of underground distribution feeder
(Source: MEA)

Category	Components	Unit	Unit Material Cost	Unit Manpower Cost
Cable container				
	Duct	m	900.00	600.00
	Manhole	set	120,000.00	80,000.00
	Cable support	set	7,742.00	5,919.20
Cable assembly				
	Underground cable	m	1,116.25	226.00
	Splice	set	3,470.96	1,596.00
	Terminator	set	8,600.00	1,596.00
Switches				
	RMU	set	450,000.00	12,000.00
	ATS	set	500,000.00	12,000.00

6.3.3 Determination of Resolution Cost

Resolution cost is a cost that incurred in an activity performed to prevent the occurrence or mitigate the loss caused by risk. In the view of distribution network, prevention of network failure could range from simple and cheap method to complex and costly one. The methods power utility commonly uses are replacement of poor performed components with new one, calendar-based inspection, network reconfiguration, upgrading the whole network, or design conversion. A typical resolution action that utility usually employ to reinforce its distribution network performance is shown in figure 6.3.

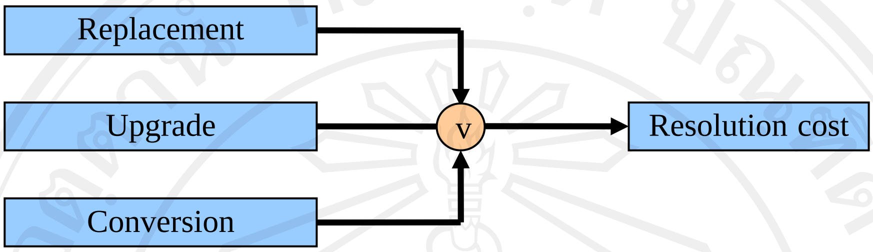

Figure 6.4 A typical resolution action employed to reinforce distribution network performance

In this thesis, only two resolution action will be focused: the network component upgrade and the entire network conversion. The cases are based upon the assumption that the current system is an overhead network. As previously mentioned, people tends to choose an underground system if the option is made available for selection. One objective of this thesis is to address the cost and other related issues in obtaining an underground distribution system by converting an existing overhead network.

The cost of each alternative can be simply computed by using work breakdown structure and unit cost. For example, to estimate the cost incurred in the underground feeder project, it is required to break down the underground feeder into several components. Then estimate the number that each component will be used to form up the entire underground feeder. The total estimated cost of the feeder can be by summation of product between number of component used and unit cost. Table 6.8 shows the cost estimation of underground feeder example.

Table 6.8 Example of cost estimation of underground feeder (1 circuit-km)

Components	Qty	Unit	Cost
Duct	1000	m	1,500,000.00
Manhole	4	set	200,000.00
Cable support	4	set	54,644.80
Underground cable	3,000	m	4,026,750.00
Splice	9	set	45,602.64
Terminator	3	set	30,588.00
Total cost			6,457,585.44

The cost components discussed above are regarded as direct cost. However, in real world project execution, not only these direct costs are involved but also the others such as overhead cost, project management cost, consulting cost, etc. need to be taken into account as well. Furthermore, if the project life cycle is to be considered, the operation and maintenance cost as well as the disposal also need to be examined. Details of such estimation will not consider in this thesis.

6.4 Total Financial Impact

Figure 6.5 below depicts overall framework for financial impact evaluation for the risk of feeder failure. The predicted cost of outage could be obtained by simply multiplying the total outage cost (if feeder failure actually occurs) with the percentage of failure possibility calculated using the methods discussed in chapter 5.

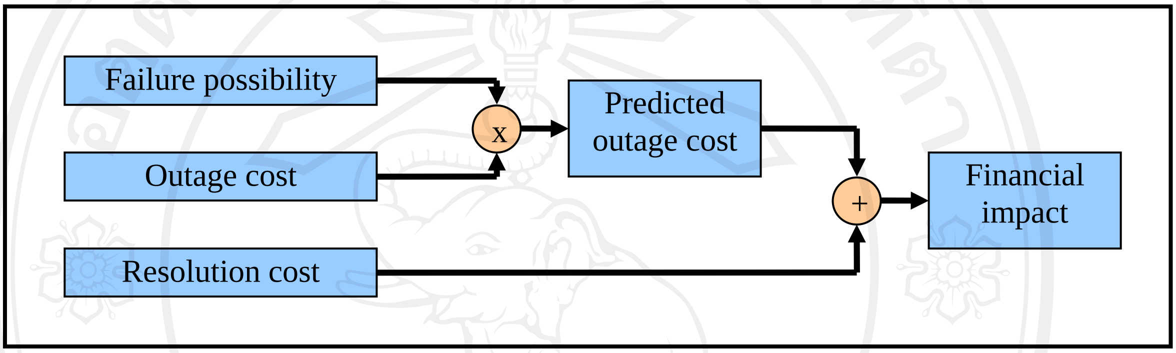

Figure 6.5 Framework for financial impact evaluation

The total financial impact, however, simply means the cost-benefit analysis among alternative actions. That is, what cost stakeholders must bear and what benefit they will gain if distribution utility:

- carries on using current network,
- upgrades their current network, or
- replace the whole network with new design

In the quantitative evaluation of cost-benefit analysis, the terms *cost* and *benefit* is defined as follows:

- Cost comprises of two components:
  - Remaining value on fixed asset of the feeder replaced before the end of depreciation period. On the other hand, it can be said that the certain value of asset has been already consumed from the beginning till present. Figure 6.4 shows the loss of fixed asset by prevention replacement. The estimation of remaining value on fixed asset of the feeder replaced before the end of depreciation period can be simply computed using the concept of linear depreciation.
  - Extra cost required for the introduction of resolution action. For example, if an overhead system is replaced with new overhead system of same design, the cost for obtaining new system is not considered as *cost* because utility has to have the overhead line to deliver the power

anyway. But if replaced by underground system, the additional cost will be regarded as *cost*.

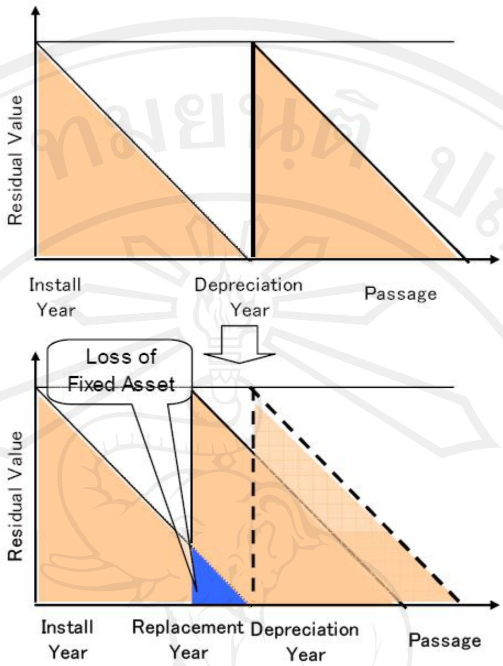

Figure 6.4 Loss of fixed asset by prevention replacement [157]

- Benefit is the cost saving that stakeholder gain from feeder reliability improvement which defined as:
  - o Customer's outage cost
  - o Utility's loss of energy sale
  - o Utility's repair cost

Let take a numerical example to demonstrate the how total financial impact on risk of feeder interruption can be evaluated.

- Feeder is expected to operate for 40 years; it has been already in serviced for 25 years; the installation cost calculated at present year is 1,000,000 Baht; using the line amortization [158] then so the remaining value is now 375,000 Baht.
- If continue using the feeder, outage cost estimated for all stakeholders is 1,500,000 Baht.
- If new design is introduced and the cost of obtaining new feeder is 2,000,000 Baht at present year then the extra cost is 1,000,000 Baht (2,000,000 Baht to obtain new designed feeder minus 1,000,000 Baht of existing design). And the new feeder can reduce outage cost down to 100,000 Baht.
- The benefit gained of 1,400,000 Baht (outage cost of 1,500,000 Baht if continue using the old feeder minus outage cost of 100,000 introduced by new design) as compared to the cost borne of 1,375,000 Baht (old feeder

remaining value of 375,000 Baht plus extra cost of 1,000,000 Baht to obtain a new design) thus makes the replacement project financially preferable.

In conclusion, the cost figures obtained this cost assessment module provide the decision maker with both feeder failure damage cost and failure prevention cost. It is now depending on what decision he would make. Should he base his decision solely on the cost figure or should he take another matter into account? The following chapters would investigate further how the asset manager can make an effective decision.