RÉPONSE D'HYDRO-QUÉBEC DISTRIBUTION
À L'ENGAGEMENT NO. 2

Engagement HQD-2 :

Résultats de l'étude d'impact économique des interruptions faite par le Distributeur à partir de l'exercice de balisage (présentation du 1er juin 2005, pages 15 et 16)

Réponse à l'engagement HQD-2:

Lors de la rencontre préparatoire tenue le 1er juin dernier, la Régie s'est informée auprès du Distributeur de l'impact économique des interruptions de service sur les clients, en général et sur le secteur industriel en particulier.

Le Distributeur a alors pris l'engagement de déposer des analyses sur la quantification des interruptions de service. Ces études ont été réalisées à la demande du Distributeur dans le cadre de l'automatisation du réseau de distribution.

Les conclusions de ces dernières n'avaient pas été intégrées à la demande R-3565-2005 en raison de l'absence d'une méthodologie reconnue par l'industrie. Les méthodes d'évaluation contenues dans ces différentes études présentent une grande diversité contribuant à des écarts importants dans les résultats d'analyse d'impacts.

Certaines de celles-ci ont été appliquées à la situation du Québec et les estimations obtenues avancent un potentiel de diminution de l'impact économique des pannes variant entre 70 M$ et 170 M$ selon la méthode utilisée.

Deux études exposant les différentes méthodologies d'évaluation sont annexées au présent engagement :

1. Valeur de l'amélioration de la fiabilité de service suite à l'automatisation du réseau de distribution, Institut de recherche d'Hydro-Québec (IREQ), Décembre 2004, révision Juin 2005
2. Cost of Outages, Jeffrey D. Lamoree, EnerNex Corporation, October 2004

Hydro Québec
Institut de recherche

Rapport

Valeur de l'amélioration de la fiabilité suite à l'automatisation du réseau de distribution

Décembre 2004
Révision Juin 2005

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Valeur de l'amélioration de la fiabilité suite à l'automatisation du réseau de distribution

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Introduction

Ce rapport présente une évaluation de la valeur sociale des gains en fiabilité apportés par l'automatisation du réseau, fondée sur les coûts des interruptions.

Afin d'en déterminer l'ordre de grandeur, la méthode d'évaluation utilise, complète et adapte des données obtenues de différentes sources :

- Hydro-Québec : Hydro-Québec dispose de plusieurs données recueillies à l'aide d'analyses économiques et de sondages auprès de sa clientèle.

- Électricité de France et IEEE : Ces sources ont développé des méthodes d'évaluation reposant sur des fonctions de coûts mettant en relation la puissance interrompue et l'énergie non livrée.

- PRS[i] et UofS[ii] : Ces sources ont développé des méthodes d'évaluation reposant sur des fonctions de coûts mettant en relation la durée des interruptions et la catégorie de clientèle.

Ces données sont appliquées aux résultats détaillés des analyses de fiabilité où chaque interruption est qualifiée par sa durée, sa puissance interrompue et l'énergie non livrée. Cette analyse a été réalisée à l'aide du logiciel prototype FIORD[1] développé par l'IREQ.

1 L'évaluation des conséquences des interruptions d'électricité chez les clients

L'évaluation du coût d'une interruption d'électricité en fonction des conséquences chez les clients résulte de l'analyse du processus déclenché par cet événement. Tel qu'illustré à la Figure 1, ce processus résulte en diverses conséquences déterminant le coût total.

Le coût total est la différence entre la situation réelle et la situation qui aurait prévalu sans l'interruption. Il est donc une évaluation différentielle de la somme des éléments suivants :

1. Salaires versés aux employés pour le surtemps nécessité par l'interruption.
2. Achats de biens et services en remplacement des pertes matérielles et en réparation des dommages encourus.
3. Ventes non réalisées.
4. Travail non rémunéré.
5. Conditions de travail dégradées.
6. Service dégradé.

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[i] Population Research Systems

[ii] University of Saskatchewan

Certains de ces éléments correspondent à des coûts réels (1, 2 et 3). D’autres doivent être quantifiés en termes de coûts à l’aide de modèles appropriés (4, 5 et 6).

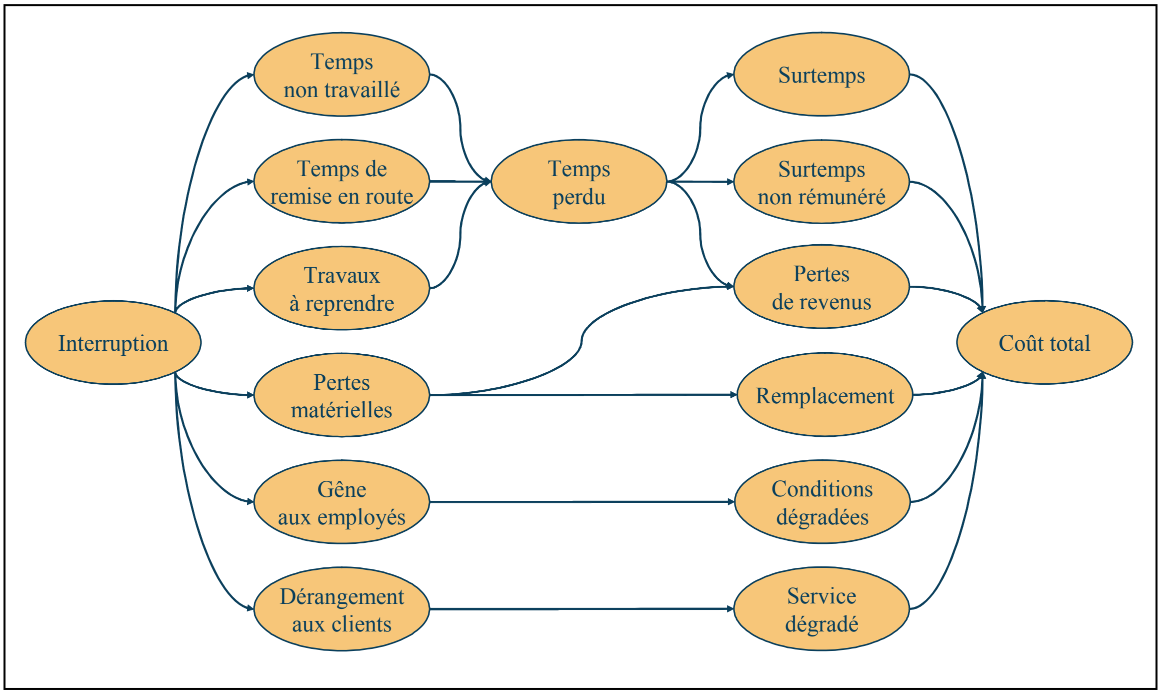

Figure 1 - Les déterminants du coût d'une interruption

Ce modèle s’applique aux clients subissant une interruption dans le cadre d’une activité économique. Pour la clientèle résidentielle, l’élément 6 correspondant à une dégradation de la qualité de vie devient prépondérant mais les autres éléments peuvent s’appliquer de façon plus ou moins importante.

Les sondages auprès des clients subissant des interruptions constituent un outil intéressant afin de faire ressortir les variables déterminantes et la valeur monétaire que les clients y accordent.

Ces sondages utilisent des questionnaires fondés sur le modèle du processus déclenché par l’interruption et sur des modèles économiques permettant d’en évaluer le coût associé.

Pour la clientèle résidentielle, différentes approches permettent d’associer un coût au dérangement causé par l’interruption :

- Demander au client combien il serait disposer à payer pour éviter l’interruption *(Willingness to pay)*.
- Demander au client combien il voudrait recevoir en compensation pour l’interruption.
- Demander au client quel est le coût des moyens de mitigation requis pour annuler le dérangement causé par l’interruption.
- Demander au client d’attribuer une cote de pondération à différentes situations dérangeantes et comparer ces pondérations à une situation de référence dont le coût a été établi par une analyse économique.

2 État de l'art

2.1 État de l'art à l'externe

L'étude commandée par Hydro-Québec à la firme EnerNex illustre la diversité des approches utilisées pour évaluer les coûts des interruptions et les différences entre les valeurs utilisées :

1. Population Research Systems[2] propose des fonctions de coûts selon la durée de l'interruption et la taille de l'entreprise, stratifiés selon la catégorie tarifaire.

   Tableau 1 - Coûts ($2004) des interruptions selon Population Research Systems

Durée	Résidentiel *Willingness to pay* ($/kWh annuel) (1996-2000)	Commercial et Industriel (petits) ($/kWh annuel) (2001-2002)	Commercial et Industriel (grands) ($/kWh annuel) (2001-2002)
< 2 min	0.00027	0.0028	0.0066
2 – 20 min		0.0051	0.0039
1 h	0.00042	0.0072	0.0033
2 h			
4 h	0.00045	0.0151	0.0073
8 h	0.00032	0.0276	
>8 h	0.00164		

2. Électricité de France[3] utilise des méthodes macro-économiques pour établir une fonction générale des coûts des interruptions :

   a. Coût du kilowattheure interrompu:
      FRF60 (US$8) jusqu'à 30 MWh interrompus;
      FRF130 (US$17.4) pour plus de 50 MWh interrompus
      (Note: interpolation linéaire entre 30 et 50 MWh).
      Coût d'un kilowatt interrompu : FRF5 (US$0.67).

   b. Jusqu'à 1995, EDF utilisait le ratio PIB/ Énergie consommée. Depuis 1995, la valeur est mieux adaptée à l'économie globale de qualité de l'alimentation et au taux de retour sur l'investissement. Dans l'avenir, avec la nouvelle organisation du secteur d'électricité, ces paramètres économiques devraient se développer selon la réglementation en vigueur.

3. IEEE[4] propose une fonction de coûts selon la catégorie de clientèle :

   a. Pour les industries, le coût moyen d'une interruption est 6.43 $/kW + $9.11/kWh non livré.
   b. Pour les commerces, le coût moyen d'une interruption est $21.77/kWh non livré..

Le rapport présente également d'autres études portant sur des usages plus spécifiques de l'électricité.

En plus des références de ce rapport, il est important de citer :

- Les travaux de l'équipe du professeur Roy Billinton de University of Saskatchewan[5] qui ont produit des fonctions de coûts selon la durée de l'interruption et la taille de l'entreprise, stratifiés selon la classification des activités économiques des entreprises.

Tableau 2 - Coûts ($2004) des interruptions selon University of Saskatchewan (1993)

Durée	**Résidentiel** *Moyens de mitigation* **($/kWh annuel)**	**Commercial ($/kWh annuel)**	**Industriel ($/kWh annuel)**
< 2 min		0.00114	0.00949
2 – 20 min	0.00001	0.00271	0.01003
1 h		0.00809	0.01263
2 h	0.00008	0.01419	0.01475
4 h	0.0009	0.03211	0.02251
8 h	0.00199	0.05511	0.04205
>8 h	0.00220	0.11407	0.05605

- L'utilisation systématique des coûts des interruptions dans les pays scandinaves[6]. En Norvège, dès 1995, la planification se fait en fonction des coûts des interruptions selon des méthodes normalisées et en fonction d'une spécification claire de collecte de l'information commune à toutes les entreprises (FASIT). Ce coût est calculé selon une méthode normalisée (CENS – Cost of Energy Not Supplied) différenciant 6 catégories de clientèle. Nous ne disposons pas, à l'heure actuelle, de données chiffrées provenant de ces sources.

2.2 État de l'art à Hydro-Québec

2.2.1 Études macro-économiques

Au cours des années 1980, la direction Planification générale d'Hydro-Québec a produit quelques études visant à évaluer les coûts des interruptions sur une base macro-économique. Ces études avaient notamment servi à évaluer le coût d'une panne majeure ou générale du réseau de transport[7].

2.2.2 Sondages

En 1989, Hydro-Québec réalisait un sondage auprès d'environ 1600 entreprises dans le *secteur industriel*[8], basé sur le modèle décrit à la Figure 1.

Un second sondage a été réalisé en 1991 auprès du *secteur résidentiel*[9]. Il a permis d'établir la valeur relative du dérangement causé par les interruptions en fonction du moment, de la durée et du préavis.

Établi dans un contexte de planification, le coût des interruptions a été établi en 1992 à l'aide des informations ainsi obtenues ,et en supposant que l'interruption survient aléatoirement à tout moment de l'année.

Il avait alors été estimé que le coût unitaire établi pour la clientèle *commerciale et institutionnelle* pour une panne d'une heure survenant pendant le jour pouvait être fixé arbitrairement comme équivalent à celui d'une panne d'une heure pour le secteur résidentiel survenant le soir. *Cette hypothèse s'était avérée très basse* par rapport aux valeurs présentées dans la littérature[10].

Les coûts unitaires pour le secteur résidentiel ont été rajustés suite à une analyse économique réalisée en 1997. Cette analyse visait à établir le coût qui correspondait le mieux aux pratiques d'exploitation en cours à Hydro-Québec[10]. Les nouveaux coûts sont 2,4 fois les coûts spécifiés alors, fixant à 8 $/(kWh/h) le coût d'une interruption d'une heure. Il est intéressant de noter que cette approche indirecte avait conduit à un coût se rapprochant du salaire minimum en supposant que le nombre de personnes affectées par l'interruption est de l'ordre de 2 à 2,5.

Il en résulte qu'Hydro-Québec dispose actuellement de ses propres données pour les secteurs résidentiel et industriel, mais elle doit déduire les données pour le secteur commercial et institutionnel à partir de publications externes.

3 Résultats obtenus

3.1 Méthode d'analyse

L'évaluation de la valeur des gains en fiabilité obtenus de l'automatisation du réseau est calculée de la façon suivante :

1. Évaluation de la fiabilité pour chacune des lignes du réseau avec ou sans automatisation :
    a. Répartition des fréquences d'interruptions selon leur durée.
    b. Calcul des puissances interrompues et de l'énergie non livrée.
2. Harmonisation des paramètres des différentes méthodes :
    a. Conversion en dollars canadiens et inflation.
    b. Conversion en fonction des kVA raccordés (unité utilisée dans l'analyse de fiabilité).
    c. Agrégation des paramètres définis par strate pour un traitement indifférencié.
3. Calcul des coûts des interruptions pour le scénario de base et le scénario automatisé, selon les méthodes disponibles :
    a. Méthodes EDF et IEEE.
    b. Méthodes Populations Research, University of Saskatchewan, Hydro-Québec.

Tous les résultats présentés ici ne s'appliquent qu'aux pannes ayant leur origine sur le tronc principal des lignes du réseau de distribution.

3.2 Valeur des gains en fiabilité obtenus de l'automatisation

À partir des données de fiabilité obtenues pour les scénarios choisis, des données historiques de fiabilité et des données de coûts des interruptions, il a été possible d'obtenir les résultats suivants pour le programme d'automatisation appliqué aux lignes sélectionnées du réseau de distribution d'Hydro-Québec (environ 1100 lignes sur 2700).

Tableau 3
Coûts des interruptions associés au plan d'automatisation selon les cinq méthodes de calcul utilisées
(Coût total pour toutes les lignes en M$2004)

	EDF	*IEEE*	*HQ*	*PRS*	*UofS*
Base (moyenne des années 2000 et 2001)	208	205	341	586	714
Automatisation des lignes sélectionnées	138	136	261	454	543
Coûts évités	***70***	***68***	***79***	***132***	***170***
%	34%	33%	23%	23%	24%

Conclusion

1. Les données obtenues de diverses sources pour évaluer le coût des interruptions présentent des écarts importants. Ces écarts peuvent être dus à des différences méthodologiques ou à des différences entre les populations étudiées.
2. Les méthodes basées sur le coût de la puissance interrompue et de l'énergie non livrée (EDF et IEEE) accordent moins d'importance aux pannes de courte durée. Tandis que les méthodes basées sur le coût en fonction de la durée (HQ, PRS et UofS) reflètent le fait que les sondages indiquent un coût de base important dû à la simple occurrence de l'interruption. Ceci explique la différence entre les gains en pourcentage attribués à l'automatisation selon les différentes méthodes.
3. Les données d'EDF et de IEEE, fondées sur une approche macroéconomique, conduisent à une évaluation moins élevée des coûts des interruptions. Les méthodes PRS et UofS, fondées sur des sondages auprès des clients conduisent à des évaluations plus élevées. La méthode Hydro-Québec utilise des sondages pour établir le processus suivant l'interruption mais évalue les coûts résultants du processus par une analyse économique fondée sur les paramètres de l'entreprise sondée ou sur une évaluation macro-économique du dérangement. Ses résultats se situent au milieu du spectre des résultats.

Références bibliographiques

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[2] J. D. Lamoree (EnerNex Corporation), *Cost of Outages*, Rapport produit pour Hydro-Québec, 2004

[3] G. Bernard, J.-L. Farges (Électricité de France), *Reliability Takes Center Stage*, T & D World, 2001 http://tdworld.com/mag/power_reliability_takes_center/index.html

[4] IEEE standard 493-1997

[5] R. Billinton, G. Wacker, G. Tollefson (University of Saskatchewan), *Customer costs associated with electrical supply failures*, Canadian Electrical Association, Montréal, 1993

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[9] SOM, Hydro-Québec, *Étude sur l'impact des interruptions de service électrique en milieu résidentiel,* décembre 1991

[10] Éconotech, Hydro-Québec, *Incidence économique de la compatibilité électromagnétique : étude des secteurs institutionnel et commercial,* janvier 1997

Cost of Outages

Performed for

HYDRO QUEBEC

Performed by

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Finalized
October 14, 2004

Table of Contents

1. Executive Summary

Electric Power Outages

Electric power outages (interruptions) are a subset of voltage variation power quality events. An outage is an event characterized by the supply voltage being close to zero.

IEEE 1159 defines three types of supply interruptions:

- Momentary Interruption: complete loss of Voltage (< 0.1 or 0.01 pu) on one or more phases for a time period between 0.5 cycles and 3 sec.
- Temporary Interruption: complete loss of Voltage (< 0.1 or 0.01 pu) on one or more phases for a time period between 3 sec and 1 min.
- Sustained Interruption: any interruption not classified as a momentary or temporary interruption.

Such interruptions can be caused by different events, such as short circuit faults, natural disasters (hurricanes, tornadoes, earthquakes), planned maintenance outages and many others.

The review of the available publications shows that even though there are some estimates of the aggregate cost of unreliable power to the U.S. and other economies, the estimates are not consistently documented and in some cases are based on questionable assumptions or survey results that are not objective.

The costs of large-scale outage events, such as the August 2003 blackout or the different hurricanes (as well as other wide area power outages) are not well documented. This is due on one hand to the huge number of affected residential or business customers. On the other hand, in the cases where the outages are the result of a natural disaster, it is difficult to separate the costs of electric interruptions from damages caused by other disaster features (e.g., property damage from wind or water.

Many of the studies developing methods for the evaluation of outage costs are based on hypothetical outage costs obtained from outage cost surveys. They are tested on abstract power system models that may be very different from real system conditions.

The worth is generally known as the outage costs and can be evaluated using operating statistics of the components installed in the system to obtain the Interrupted Energy Rate (IER) or the Value of Lost Load (VOLL). Therefore, to evaluate the outage cost, it requires a good understanding about customer's damages when an outage has occurred. The outage cost can also be used as an unreliability index and represented as reliability worth to be analyzed and compared for future plans and operations.

One of the reasons that it is so difficult to evaluate the outage costs is that the interruption may cause both direct and indirect damages.

Loss of production and raw materials, inconvenience and damages to life and assets are its direct result. While other damages such as crimes, relocation of factories or offices as well as the cancellation of orders as a result of late deliveries can be indirectly caused by outages.

Impacts and outage cost should be estimated in monetary value, which however is quite difficult in practice. Estimating the impacts on raw materials damaged during an outage is possible, while estimating the impacts on residential customers is very difficult. The reason is because the perspectives of each consumer on the impacts of outages differ according to his or her objective of power usage. Consumer categories, power quantity, interrupted activities, duration and period of outages should thus be the criteria of cost estimation.

Factors

Customer interruption costs due to failure in electrical energy supply depend on many factors.

The following is a list of some of the more common factors that have effect on the outage costs:

- type of load
- duration of the outage event
- frequency of interruption
- time of day
- day of the week (weekday/weekend)
- time of year (season)
- availability of standby systems
- advanced notice
- changes in staffing and training

The cost of each specific event may vary significantly based on a combination of the above listed factors.

In developing the customer damage model we have to calculate the total damage cost which comprises several types of damages. For industrial, business and services customers, the damage cost of each customer is based on six main types of damages, as follows:

1) Salary or work payment
2) Cost of loss of profit opportunity
3) Overtime payment
4) Cost of loss of raw material or production
5) Cost of re-starting the process

6) Cost of damaged equipment

Assessment of Outage Costs

By weighting the average or models of different sectors (such as the ones listed earlier), classified by electric tariff, a Composite Customer Damage Function (CCDF) can be obtained.

The outage cost can be evaluated using the obtained CCDF and the actual interruption statistics.

The obtained outage costs can be divided into two types as follows:

1) Interrupted Energy Rate (IER) in Currency /kWh

2) Interruption Cost Per Event (ICPE) in Currency /event

The customer damage functions developed using the survey method can be used to calculate an average cost of unserved energy for each customer group and for an entire service area. The index is designed as the Interrupted Energy Assessment Rate (IEAR) expressed in (Currency/kWh). Sensitivity studies show that the IEAR is relatively stable at various load levels and under different operating conditions.

The second component required in the evaluation of the Marginal Outage Cost incorporates the probabilities of capacity outages and the system load demand in the form of quantitative risk index.

The most suitable risk index for the evaluation of the marginal outage cost is the Expected Unserved Energy (EUE). The effect of load changes on EUE values is evaluated at incrementally different load levels (e.g. a load increase of 1 MW).

Outage Costs

The cost of outages is very difficult to estimate, because in many cases the power outage is not a single event, but the result of natural disaster or other event that cases damages as well.

They also vary by country or even by region, as is the case in the United States.

The results from the analysis of the different tables included in this document, as well as in many other surveys reported in the literature show a very clear trend in the effect of the outage duration on the outage costs.

The cost increases with the increase in the outage interruption until it reaches a value typically between 4 and 8 hours. After that it may stabilize or in some cases even decline.

The chart below is from the average costs of all surveyed outages for large commercial and industrial customers in the United States over a period of more than 15 years.

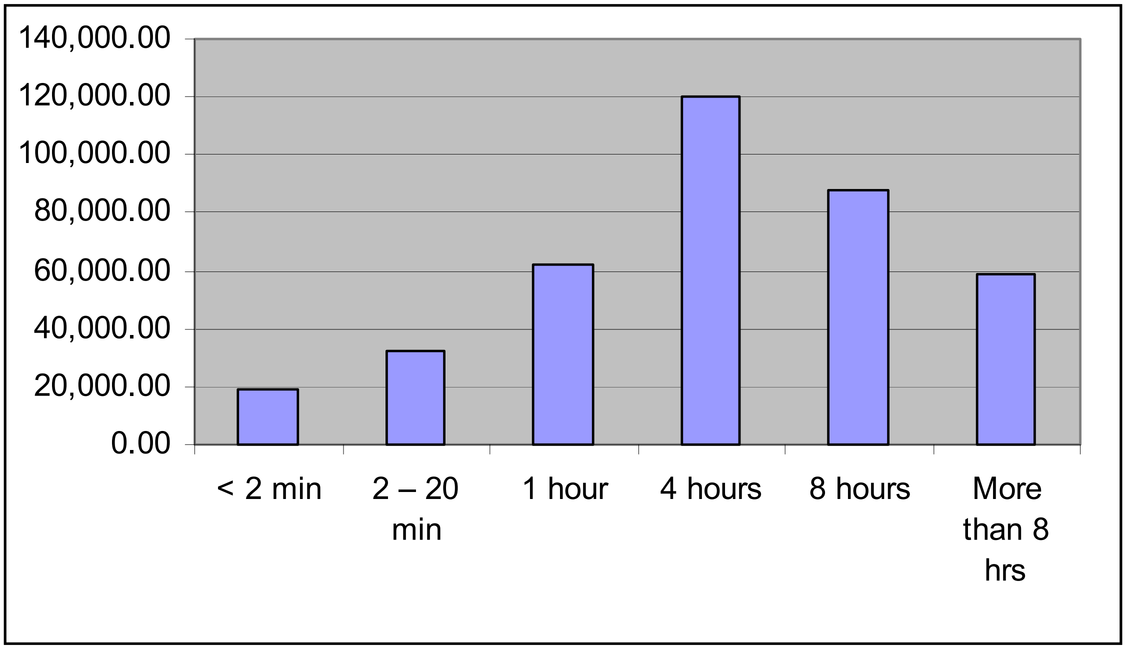

Figure 1 - Outage costs as a function of the outage duration for large customers

The bulk of the data was from US utilities. In looking at the different regions from the US, there is quite a difference as was pointed out earlier. It was hard to ascertain from the surveys why this was so, but our assumption was that the numbers from the Northeast would be a good approximation given the geographic proximity and similar weather patterns. We've found several sources that said that cost of business in Canada is 9% cheaper than in the US. So you could argue that the US figures given are 9% higher than what they would be for Canada.

Customer Attitude

It is concluded that customers had difficulty quantifying effects of hypothetical outages, and most customers expect no future outages, even though outages occurred regularly in the past.

It is recommended to survey customers on a regular basis, and if possible in face-to-face meetings, since the results in this case can be very different from the results in a survey form.

Methods to Reduce Outage Costs

Consumer outage costs can be significantly reduced by considering the effect of the different factors and taking measures to implement solutions, that will result in minimal losses in the event of a power interruption.

Some of the solutions analyzed in the report are:

- Implementing emergency actions strategy
- Remote monitoring and control
- Event driven maintenance
- Reclosing
- Fuse saving schemes
- Adaptive protection
- Crew training
- Dynamic loading
- Outage forecasting
- Standby systems

2. Introduction

The electric utility industry is going through significant changes due to deregulation, along with a growing number of sensitive manufacturing processes and businesses leading to the increasing requirements for high reliability of the power supply.

The August 2003 blackout in North America demonstrated clearly that there are significant problems in many areas of the electric power system. It also showed the difficulties in the analysis of such events, including the processing of huge amounts of data (in many cases not time-synchronized), determining the actual sequence of events, as well as the cost of the loss of power to the millions of customers affected by the blackout.

Part of the problem is that there is no complete and methodical study of the data on this topic. Only such an effort will allow this data to be converted to useful information.

Electric power outages (interruptions) are a subset of voltage variation power quality events. An outage is an event characterized by the supply voltage being close to zero.

The power quality definition of a Supply interruption is: "Complete loss of voltage for a period of time".

IEEE 1159 defines three types of supply interruptions:

- Momentary Interruption: complete loss of Voltage (< 0.1 or 0.01 pu) on one or more phases for a time period between 0.5 cycles and 3 sec.
- Temporary Interruption: complete loss of Voltage (< 0.1 or 0.01 pu) on one or more phases for a time period between 3 sec and 1 min.
- Sustained Interruption: any interruption not classified as a momentary or temporary interruption.

Such interruptions can be caused by different events, such as short circuit faults, natural disasters (hurricanes, tornadoes, earthquakes), planned maintenance outages and many others.

As can be seen from the Bibliography in the last section of this report (which doesn't pretend to cover all available publications on that topic), there is a significant number of papers and studies that consider different aspects of the problem and present results from outage cost surveys.

However, even though they show some common characteristics, they are not presenting the complete picture, due to the fact that there are numerous factors that affect the results from any study based on local criteria. Probably the closest to a broader view on the cost of outages is presented in a paper based on research by the E. O. Lawrence Berkeley National Laboratory [64].

The review of the available publications shows that even though there are some estimates of the aggregate cost of unreliable power to the U.S. and other economies, the estimates are not consistently documented and in some cases are based on questionable assumptions or survey results that are not objective.

The costs of large-scale outage events, such as the August 2003 blackout or the different hurricanes (as well as other wide area power outages) are not well documented. This is due on one hand to the huge number of affected residential or business customers. On the other hand, in the cases where the outages are the result of a natural disaster, it is difficult to separate the costs of electric interruptions from damages caused by other disaster features (e.g., property damage from wind or water.

Many of the studies developing methods for the evaluation of outage costs are based on hypothetical outage costs obtained from outage cost surveys. They are tested on abstract power system models that may be very different from the real system conditions.

One of the main tasks of each utility is to generate and deliver reliable electricity to customers at reasonable prices. The prices of electricity normally vary in accordance with the state of the system, the demand for power, as well as the level of utility's reliability standards. The more reliable the supply of power, the higher the price normally is.

However, if the system reliability is low, outages tend to occur more often and will eventually result in more damages to individual customers and business sectors. If each utility utilizes the components in the electric power system close to their limit or rated capacity, the electricity price may probably be lower. This kind of operation can be achieved in exchange of lower reliability and security of the system.

Outage costs are one of the critical factors to consider in the process of finding the balance between reliability of the supply of power and the cost of electricity. The balance between economical and technical considerations is therefore necessary for the utility's operation regardless of working under competitive environment or not.

This report attempts to answer many of the questions related to outage costs. It is based on the data and information available in the multiple publications listed in the Bibliography at the end of the document. The analysis of the data is summarized in the following sections:

- Factors Affecting Outage Costs
- Methods to Assess Outage Costs
- Outage Costs
- Methods to Reduce Outage Costs
- Customer Attitude
- Use of Outage Costs
- Bibliography (Literature on Outage Costs)

In general, there is no well defined universal criteria for choosing reliability levels in power system planning and operation. It mostly depends on criteria used in the past and work experiences.

Under the present vertically integrated structure, utilities can fix the minimum requirement of capacity reserve as a percentage of the peak demand or apply a maximum Loss of Load Probability (LOLP) as its planning criteria.

In addition distribution utilities may allow the maximum power flows in any particular feeders to not exceed eighty percent of its rated capacity. However, production expansion or additional construction to enhance capacity and services at a lower price is inevitable for present and future system operation.

One of the problems faced by utilities is how to fix their own appropriate reliability and security levels. This can be solved theoretically by comparing the cost of supply and distribution with customers' benefits at different reliability levels.

The optimum reliability level will be at the balance point between the total cost of supply and the benefits from the customers. As a result, we need to estimate the cost of electricity services at different reliability levels separately from the estimation of reliability value.

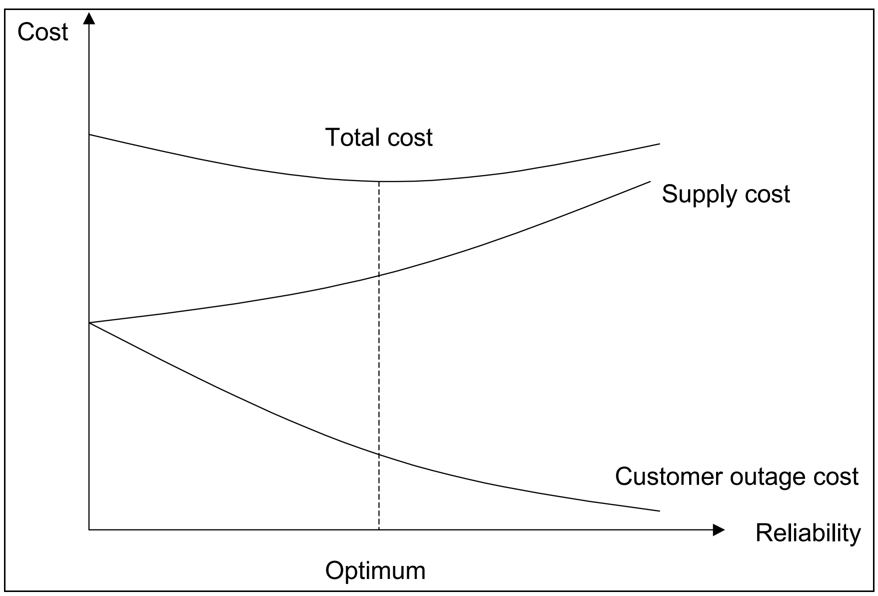

Figure 2 - Costs and reliability

The outage costs are directly related (in some cases considered identical) to the reliability worth. Though the estimation of customers' outage costs is fairly difficult, each utility has for a long time estimated its investment cost in order to obtain the required reliability level. The reliability worth evaluation is usually done through the evaluation of reliability indices, which indirectly reflects the reliability worth.

The worth is generally known as the outage costs and can be evaluated using operating statistics of the components installed in the system to obtain the Interrupted Energy Rate (IER) or the Value of Lost Load (VOLL). Therefore, to evaluate the outage cost, it requires a good understanding about customer's damages when an outage has occurred. The outage cost can also be used as an unreliability index and represented as reliability worth to be analyzed and compared for future plans and operations.

One of the reasons that it is so difficult to evaluate the outage costs is that the interruption may cause both direct and indirect damages.

Loss of production and raw materials, inconvenience and damages to life and assets are its direct result. While other damages such as crimes, relocation of factories or offices as well as the cancellation of orders as a result of late deliveries can be indirectly caused.

Impacts and outage cost should be estimated in monetary value, which however is quite impossible in practice. Estimating the impacts on raw materials damaged during an outage is possible, while estimating the impacts on residential customers is very difficult. This is so because the perspective of each consumer on the impacts of an outage differs according to his or her objective of power usage. Consumer categories, power quantity, interrupted activities, duration and period of outages should thus be the criteria of cost estimation.

One of the problems with the analysis and evaluation of outage costs, especially for residential customers and small business is the lack of accurate data on the duration, frequency, magnitude and type of load being interrupted. EPRI and E2I (the Electricity Innovation Institute) have formed the Consortium for Electric Infrastructure to Support a Digital Society (CEIDS) in an effort to provide a strategic framework for upgrading the electric system.

The Integrated Energy and Communications System Architecture (IECSA) project will develop an open, standards-based systems architecture for the data communications and distributed computing infrastructure. That will enable the integration of a wide variety of intelligent electric power system components, thus providing the required data for more accurate evaluation of outage costs. It will build upon the existing infrastructure, while at the same time leverage the newest communications and distributed computing technologies available.

3. Factors Affecting Outage Costs

Customer interruption costs due to failure in electrical energy supply depend on many factors.

The following is a list of some of the more common factors that have effect on the outage costs:

- type of load
- duration of the outage event
- frequency of interruption
- time of day
- day of the week
- weekday/weekend
- time of year (season)
- availability of standby systems
- advanced notice
- changes in staffing
- training
- equipment count

The type of load is one of the main factors that determine the cost of an outage. For example, a manufacturing facility producing microprocessors may loose millions of dollars as a result of a short interruption that will cause just the inconvenience of setting the flashing alarm clock for a residential customer.

The duration of an outage can be as short as several cycles (in the case of short circuit fault, followed by a breaker trip and successful high-speed reclosing) – a momentary interruption. Sustained interruptions may last for several minutes to weeks or months.

The duration of an interruption is a function of the cause of the fault. Equipment failure (for example a power transformer fault) may result in long outage duration due to the fact that it is difficult to deliver and put in service even a temporary replacement (mobile substation).

On the other hand a tree hitting a transmission line may result in more frequent interruptions, but with a very short duration – determined by the protective relay operating time, the breaker tripping time, the reclosing interval and the breaker closing time.

The following (non-exhaustive) figure shows some typical causes of customer outage duration.

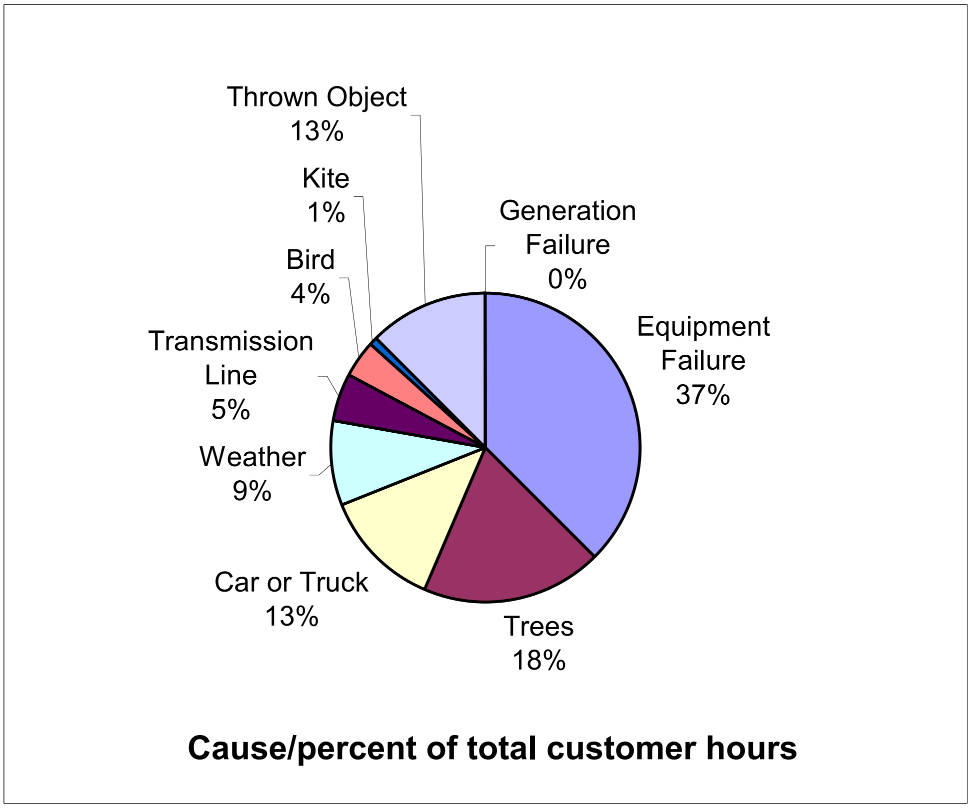

Figure 3 – Outage Causes

The time of day is another important factor. It is obvious that if an outage occurs after working hours in an office, the outage costs will be lower than it it occurred during working hours.

A similar factor is the day of week. Outage cost in the same facility will vary significantly for an outage that occurred during the week, compared to a weekend outage.

The time of year can be a significant factor for the effect of an outage not only to business, but to residential customers as well. Loss of air conditioning in a hot summer day may not be accepted the same way as an outage in the same geographical area in the fall. Again, all the other factors will have to be considered in the analysis.

The frequency of interruptions depends on the cause of the outage. Since many outages are the result of short circuit faults, the cause of the fault may affect the outage frequency, as well as the outage duration (as a function of the repair time).

The table below shows some statistics that illustrate the failure rate and repair time.

Table 1 - Failure statistics (for permanent faults), average values

Type of Component	Failure rate* [No. per year]		Repair time [hours/outages]	
	Case 1	Case 2	Case 1	Case2
Lines	6.0	0	2.0	2.0
Cables	5.0	4.7	13.7	13.7
Circuit breakers	1.7	1.3	6.0	5.4
Control equipment	5.0	1.7	0.8	0.8
Disconnector	1.4	0.07	1.5	0.8
Distribution x-er	1.0	0.18	3.0	7.8

(*) Per 100 units. The unit is km for lines and cables.

Availability of standby systems can significantly reduce the cost of an outage by providing power to the most sensitive loads in a facility.

Advance notice for a scheduled outage can significantly decrease the outage cost, because it will allow the customer to take measure and avoid damage to sensitive equipment. Depending on the type of load, the advanced notice requirements may vary significantly. In some cases minutes may be sufficient, while in others a couple of days will be needed.

Changes in staffing and training also significantly affect the outage costs, because more experienced and well trained crews will repair damaged equipment much faster than a new crew with inadequate training. The duration and cost of outages caused by natural disaster that affects a wide area will be a function of the number of crews available for restoration of the power supply.

In developing the customer damage model we have to calculate the total damage cost which comprises several types of damages. For industrial, business and services customers, the damage cost of each customer is based on six types of damages, as follows:

1) Salary or work payment
2) Cost of loss of profit opportunity
3) Overtime payment
4) Cost of loss of raw material or production
5) Cost of re-starting the process
6) Cost of damaged equipment

We can see that these damage costs may vary with the interruption duration until they reach a certain value, i.e. they last longer than a specific duration. After this point the damage cost could be considered constant. For example, the cost of loss of profit opportunity varies with the interruption duration only if the outage does not last longer than 8 hours. It means, if the working time of this customer is 10 hours per day, this damage cost is proportion to the interruption duration until it reaches 10 hours. After that it remains constant and equal to the cost of 10 hours. If the outage is longer than 24 hours, then the cost will start changing again.

The damage costs of types 3–6 normally vary with interruption duration, usually up to about 8 hours. The customer will be able to manage his or her business to alleviate the damage cost. Therefore, the damage cost of the interruption, which last longer than 8 hours will be constant and equal to those of 8 hours. However, the first damage cost, salary, depends strongly on the damage cost for the entire outage duration.

If there is an electric interruption, most of the total damage cost of industrial factory customers is dominated by the damage cost from salary, loss of profit opportunity and overtime charged.

For most business and service customers loss of profit opportunity has dominated most of the other damage costs since their damage values are less compared to this cost.

The figure below shows the characteristics of the outage cost/duration function for each category.

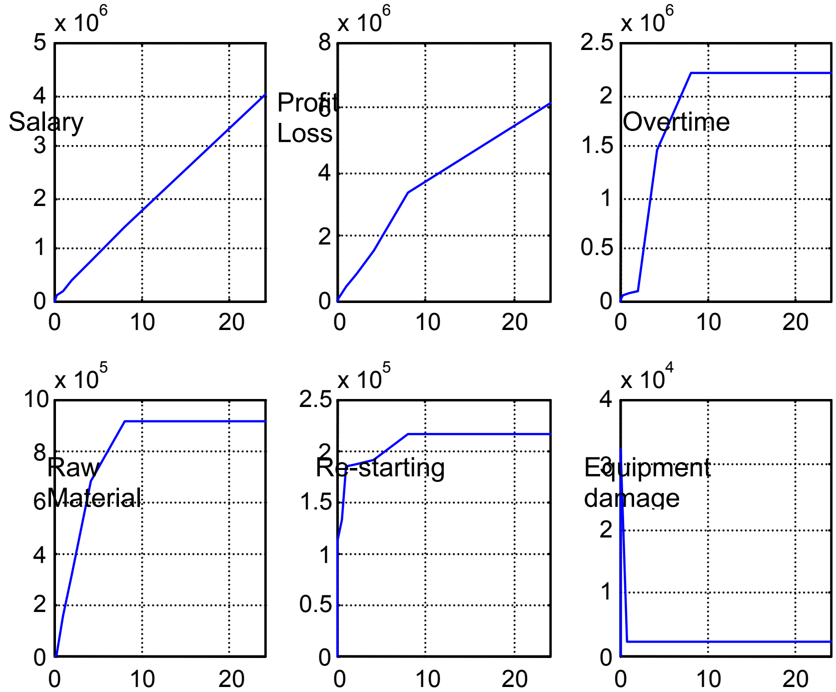

Figure 4 – Outage Cost/Duration for Various Categories

4. Methods to Assess Outage Costs

Outage cost surveys

Outage cost studies are based on different methods. However, all methods have a common component – a questionnaire that is used for gathering well organized data.

The engineering teams that perform the study had to develop questionnaires so that they would suit the main categories of consumers.

Typically there are three main categories of consumers:

- household sector
- industrial sector
- business and service sector

Data used in outage cost studies is gathered using different methods:

- from interviews with power consumers
- from interviews with concerned persons in different agencies
- from interviews with households
- surveys via internet for those who want to express their opinion directly

Questionnaires for direct interview and for the internet should be similar in order to ensure that similar kinds of data is obtained.

The outage cost models are developed according to electricity tariffs that classify customers into different categories. Below is a list of some typical categories:

- Residential
- Small business
- Medium business
- Large business
- Specific business
- Government and non-profit organizations
- Agricultural pumping

The customers of the second, third and fourth types are further divided into two sectors, i.e. industry and business and services.

The industrial sector, usually the most susceptible to outage damages is divided into sub-classifications according to the existing standards or other criteria. Some examples are:

- Computer products

- Electronics
- Automotive
- Energy
- Pharmaceuticals
- Food, beverage & tobacco
- Textile and leather products
- Wood and wood products
- Pulp and paper
- Chemical and rubber
- Non-metallic mineral
- Basic material
- Fabricated metal
- Other manufacturing

The business and service sector can also be very sensitive to outage damages and can also be divided into sub-classifications according to the existing standards or other criteria. Some examples are:

- Financial institutions
- Telecommunications
- Information technology
- Insurance
- Retail
- Banking
- Transportation
- Utilities
- Health care
- Professional services
- Construction and engineering
- Media
- Hospitality and travel

The outage cost for each of the above listed categories will be different and will also change in a different way as a function of the outage duration, outage frequency, or any of the other factors described earlier in this section.

Methods to Assess Outage Costs

As can be seen from the list of sources in the Bibliography section of this document and the analysis later in this section, there is a large variety of methods to assess the costs of an outage.

Below we are showing a more generic method that can be widely implemented. If necessary, more precise methods are available in the listed literature.

By weighting the average or models of different sectors (such as the ones listed earlier), classified by electric tariff, a Composite Customer Damage Function (CCDF) can be obtained.

We can see that the CCDF, which is in the unit of Currency/kW_{avg}, is the function of interruption duration, and it can be written as *CCDF(t)*. The *CCDF(t)* is used in outage cost evaluation later.

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

where:

i is customer type

n is a number of each customer type

c_i is energy consumption of customer type i

$SCDF_i$ is sector customer damage function of customer type i

LF_i is load factor of customer type i

The outage cost can be evaluated using the obtained CCDF and the actual interruption statistics.

The obtained outage costs can be divided into two types as follows:

1) Interrupted Energy Rate (IER) in Currency /kWh

2) Interruption Cost Per Event (ICPE) in Currency /event

These costs are then calculated from CCDF based on interruption statistic by using these equations.

$$IER = \frac{Interruption\,Cost}{Energy\ Not\ Supplied} = \frac{ECOST}{EENS} = \frac{\sum_{j=1}^{n} CCDF(t_j) \times P_j}{\sum_{j}^{n} P_j \times t_j} \qquad (2)$$

$$ICPE = \frac{Interruption\,Cost}{A\,number\ of\ Outage\ Event} = \frac{ECOST}{n} = \frac{\sum_{j=1}^{n} CCDF(t_j) \times P_j}{\sum_{j}^{n} j} \qquad (3)$$

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.

The structure of electric utilities is undergoing dramatic changes as new and expanded service options are added. The concepts of unbundling the electric service and offering customers a range of new services that more closely track actual costs are expanding the options open to customers.

Spot pricing provides the economic structure for many of these new service options. An important component of spot prices is the Marginal Outage Cost incurred by customers due to an incremental change in load. Marginal Outage Costs are also known as “shortage costs” or “curtailment costs”.

Marginal Outage Costs are expected quantities that depend upon two major factors:

- The customer economic costs that accompany various outage levels
- The effects of load changes on the probabilities that these costs will actually be incurred.

The customer economic costs resulting from power outages can be evaluated using a number of methodologies. Generally, the customer survey method is considered to yield acceptable results. It is based on customer surveys in order to estimate their economic losses and to create customer damage functions for the different customer groups.

The customer damage functions developed using the survey method can be used to calculate an average cost of unserved energy for each customer group and for an entire service area. The index is designed as the Interrupted Energy Assessment Rate (IEAR) expressed in (Currency/kWh). Sensitivity studies show that the IEAR is relatively stable at various load levels and under different operating conditions.

The second component required in the evaluation of the Marginal Outage Cost incorporates the probabilities of capacity outages and the system load demand in the form of a quantitative risk index.

The most suitable risk index for the evaluation of the marginal outage cost is the Expected Unserved Energy (EUE). The effect of load changes on EUE values is evaluated at incrementally different load levels (e.g. a load increase of 1 MW). The marginal outage cost can then be calculated as follows:

$$\text{M.O.C.} = \text{IEAR} \times \Delta\text{EUE} \quad \text{(Currency/kW)} \qquad (4)$$

Where:

M.O.C.: Marginal Outage Cost

IEAR: Interrupted Energy Assessment Rate (Currency /kW)

ΔEUE : Change in EUE due to an incremental change in load (MWh/MW)

Spot prices can be sub-divided into two different categories: marginal operating costs and marginal outage costs. Marginal operating costs are generally defined as fuel costs and line losses costs that are incurred in serving an incremental load as well as the maintenance costs and the system security costs that vary with usage. Marginal outage costs are defined as customer outage costs related to both capacity shortages and network capacity constraints that are incurred in serving an incremental load. The marginal operating costs needed for spot pricing can be calculated using economic dispatch models. Marginal outage costs, on the other hand, are calculated by measuring the change in expected customer outage costs resulting from an incremental load change. One method of evaluating the marginal outage costs involves estimating the customer economic costs that accompany various outage levels and the probabilities that these costs will actually be incurred. Customer surveys can be used to calculate the economic cost of power outages and quantitative reliability assessment techniques used to determine the probabilities of these outages. The data collected by the survey method has been used to create customer damage functions from which an average cost of unserved energy is calculated for each customer group and for the entire service area.

Evaluation of Marginal Outage Costs Assessment Methods

Evaluation of Marginal Outage Costs associated with large generating systems can be very time consuming if exact recursive techniques are used to model the system capacity outages.

One way of decreasing the computing time involves the utilization of approximate techniques to create a generating system capacity outage model. Some approximate techniques being investigated by researchers include:

- rounded algorithm
- Gram-Charlier expansion
- high-order Edgeworth expansion
- large deviation method
- Fast Fourier Transform algorithm.

The comparison of results from the approximate techniques to the exact values calculated using the recursive techniques for very high and very low lead time values shows that the rounding and FFT algorithms provide the best accuracy for all operating reserves in a reasonable amount of computing time.

The accuracy of the large deviation method falls closely behind the first two techniques. The computing time required by this method, however, was found to be much smaller than that required by the previous techniques if the proper initial conditions were used in the Newton-Raphson iteration process.

The accuracy of the Gram-Charlier and the high-order Edgeworth expansions was found to be a function of the lead time considered. When the lead time is very short, these techniques exhibit peculiar behaviors that produce negative probabilities under certain conditions.

It is expected that the accuracy of some of these techniques will improve as the size of the system increases and/or the characteristics of its generating units are different. They will however have to be tested in each case prior to considered for actual use.

Outage Cost Assessment in Composite Power Systems

This study proposes a new analytical method for assessing the outage cost of a composite generation and transmission system. Outages of the generation system and the transmission system should be included in this study.

This method is based on three steps:

- Development of the composite power system effective load duration curve ELDC (CMELDC) from reliability evaluation of the composite power system in order to assess the outage cost.
- Formulation of mathematical expressions for the marginal outage cost function at each load point using relations between GNP (or GDP) and the electrical energy demand.
- Calculation of the outage cost by combining the proposed CMELDC with the marginal outage cost function at each load point.

5. Outage Costs

Outage costs are a broad category that is used in different ways depending on the goal of a study. There are different names used in different cases, for example:

- Outage Cost
- Value of Lost Load (VOLL)
- Interrupted Energy Rate (IER)

Population Research Systems

The following three tables show the different costs for large commercial and industrial customers for an outage duration of 1 hour [64]. The tables include data based on numerous surveys in different regions of the United States.

From the analysis of the data in the tables for large commercial and industrial customers, it is clear that there are significant differences – more than two times – in the outage costs for different regions of the country.

Table 2 – Outage Data for Large Commercial and Industrial Customers for 1 Hour Duration

Large Commercial and Industrial Outage Costs by Region- 1 Hour Duration				
Total Cost/Event				
Region	**N**	**Min**	**Average**	**Max**
All regions	2728	-	59,983.37	5,066,024.76
Northwest	834	-	28,609.22	3,822,931.79
Southwest	190	1.04	51,908.86	1,045,122.26
Southeast	1352	-	86,477.13	5,066,024.76
West	120	-	52,734.75	2,085,161.96
Midwest	232	1.00	28,735.36	1,010,000.00

Large Commercial and Industrial Outage Costs by Region- 1 Hour Duration				
Cost Per Annual kWh				
Region	**N**	**Min**	**Average**	**Max**
All regions	2728	0.0000	0.0037	0.0201
Northwest	834	0.0000	0.0066	0.0647
Southwest	190	0.0000	0.0039	0.0043
Southeast	1352	0.0000	0.0033	0.0201
West	120	0.0000	0.0073	0.0185
Midwest	232	0.0000	0.0025	0.0049

Large Commercial and Industrial Outage Costs by Region- 1 Hour Duration				
Cost Per Peak kW				
Region	**N**	**Min**	**Average**	**Max**
All regions	2728	0.000	15.522	113.843
Northwest	834	0.000	17.924	138.537
Southwest	190	0.003	21.920	28.724
Southeast	1352	0.000	14.835	113.843
West	120	0.000	32.715	93.421
Midwest	232	0.007	11.499	27.911

The following three tables show the different costs for medium and small commercial and industrial customers for an outage duration of 1 hour [64].

Table 3 – Outage Data for Small-Medium Commercial and Industrial Customers for 1 Hour Duration

Small-Medium Commercial and Industrial Outage Costs by Region- 1 Hour Duration				
Total Cost/Event				
Region	**N**	**Min**	**Average**	**Max**
All regions	10849	0.000	1,859.465	105,224.660
Northwest	3596	0.000	1,686.199	101,161.103
Southwest	3064	0.000	2,175.757	105,224.660
Southeast	3363	0.000	1,484.462	103,139.014
West	411	0.000	4,581.176	85,992.686
Midwest	415	1.000	1,369.007	75,000.00

Small-Medium Commercial and Industrial Outage Costs by Region- 1 Hour Duration				
Cost Per Annual kWh				
Region	**N**	**Min**	**Average**	**Max**
All regions	10849	0.0000	0.0037	0.0201
Northwest	3596	0.0000	0.0066	0.0647
Southwest	3064	0.0000	0.0039	0.0043
Southeast	3363	0.0000	0.0033	0.0201
West	411	0.0000	0.0073	0.0185
Midwest	415	0.0000	0.0025	0.0049

Small-Medium Commercial and Industrial Outage Costs by Region- 1 Hour Duration				
Cost Per Peak kW				
Region	**N**	**Min**	**Average**	**Max**
All regions	10849	0.000	40.025	169.444
Northwest	3596	0.000	18.411	162.900
Southwest	3064	0.000	66.391	207.135
Southeast	3363	0.000	25.792	199.882
West	411	0.000	101.787	155.502
Midwest	415	0.014	4.259	27.911

The outage cost estimates are not only affected by the multiple factors listed earlier in the document. They also change with the year when the surveys are done. This is very well illustrated in the following tables [64].

Table 4 – Large Commercial and Industrial Outage Costs by Duration and Years

Large Commercial and Industrial Outage Costs by Duration and Years					
Total Cost Event					
	Duration	**N**	**Min**	**Average**	**Max**
All years	All duration	7865	0.000	70,633.567	5,195,516.812
	< 2 min	1259	0.000	18,840.883	1,175,672.646
	2 – 20 min	437	0.000	32,093.205	4,775,036.285
	1 hour	3375	0.000	61,949.277	5,066,024.759
	4 hours	2097	0.000	119,715.433	5,195,616.812
	8 hours	568	0.000	88,223.602	4,231,974.922
	More than 8 hrs	129	0.000	58,562.166	1,036,717.063
Before 1990	All duration	843	0.000	49,190.640	4,775,036.285
	< 2 min				
	2 – 20 min	212	0.000	46,790.248	4,775,036.285
	1 hour	421	0.000	39,980.756	3,822,931.785
	4 hours				
	8 hours	210	0.000	70,077.518	4,046,444.122
	More than 8 hrs				
1990-1995	All duration	2386	0.000	116,358.802	5,195,516.812
	< 2 min	408	0.000	27,896.015	1,121,793.275
	2 – 20 min				
	1 hour	1320	0.000	101,952.281	5,066,024.759
	4 hours	658	0.000	200,111.728	5,195,516.812
	8 hours				
	More than 8 hrs				
1996-2000	All duration	3501	0.000	54,983.301	4,702,914.798
	< 2 min	651	0.000	14,977.416	1,175,672.646
	2 – 20 min				
	1 hour	1402	0.000	36,378.958	3,363,228.700
	4 hours	1202	0.000	89,214.847	4,702,914.798
	8 hours	117	0.000	144,890.380	4,231,974.922
	More than 8 hrs	129	0.000	58,562.166	1,036,717.063
2001-2002	All duration	1135	0.000	38,710.708	1710.000.000
	< 2 min	200	1.000	12,944.000	500,000.000
	2 – 20 min	225	1.000	18,245.324	576,000.000
	1 hour	232	1.000	28,735.358	1,010,000.000
	4 hours	237	1.000	51,196.203	970,000.000
	8 hours	241	1.000	76,525.116	1,710,000.000
	More than 8 hrs				

Large Commercial and Industrial Outage Costs by Duration and Years					
Cost Per Annual kWh					
	Duration	**N**	**Min**	**Average**	**Max**
All years	All duration	7865	0.0000	0.0037	0.0201
	< 2 min	1259	0.0000	0.0066	0.0647
	2 – 20 min	437	0.0000	0.0039	0.0043
	1 hour	3375	0.0000	0.0033	0.0201
	4 hours	2097	0.0000	0.0073	0.0185
	8 hours	568	0.0000		
	More than 8 hrs	129	0.0000	0.0025	0.0049
Before 1990	All duration	843	0.0000	0.0037	0.0201
	< 2 min		0.0000	0.0066	0.0647
	2 – 20 min	212	0.0000	0.0039	0.0043
	1 hour	421	0.0000	0.0033	0.0201
	4 hours		0.0000	0.0073	0.0185
	8 hours	210	0.0000		
	More than 8 hrs		0.0000	0.0025	0.0049
1990-1995	All duration	2386	0.0000	0.0037	0.0201
	< 2 min	408	0.0000	0.0066	0.0647
	2 – 20 min		0.0000	0.0039	0.0043
	1 hour	1320	0.0000	0.0033	0.0201
	4 hours	658	0.0000	0.0073	0.0185
	8 hours		0.0000		
	More than 8 hrs		0.0000	0.0025	0.0049
1996-2000	All duration	3501	0.0000	0.0037	0.0201
	< 2 min	651	0.0000	0.0066	0.0647
	2 – 20 min		0.0000	0.0039	0.0043
	1 hour	1402	0.0000	0.0033	0.0201
	4 hours	1202	0.0000	0.0073	0.0185
	8 hours	117	0.0000		
	More than 8 hrs	129	0.0000	0.0025	0.0049
2001-2002	All duration	1135	0.0000	0.0037	0.0201
	< 2 min	200	0.0000	0.0066	0.0647
	2 – 20 min	225	0.0000	0.0039	0.0043
	1 hour	232	0.0000	0.0033	0.0201
	4 hours	237	0.0000	0.0073	0.0185
	8 hours	241	0.0000		
	More than 8 hrs		0.0000	0.0025	0.0049

Large Commercial and Industrial Outage Costs by Duration and Years					
Cost Per Peak kW					
	Duration	**N**	**Min**	**Average**	**Max**
All years	All duration	7865	0.000	19.761	116.753
	< 2 min	1259	0.000	4.619	30.845
	2 – 20 min	437	0.000	15.456	131.954
	1 hour	3375	0.000	14.982	113.954
	4 hours	2097	0.000	35.206	116.753
	8 hours	568	0.000	44.714	116.947
	More than 8 hrs	129	0.000	0.000	-
Before 1990	All duration	843	0.000	30.818	173.040
	< 2 min		0.000	0.000	-
	2 – 20 min	212	0.000	29.314	173.040
	1 hour	421	0.000	25.048	138.537
	4 hours		0.000	0.000	-
	8 hours	210	0.000	43.904	146.637
	More than 8 hrs		0.000	0.000	-
1990-1995	All duration	2386	0.000	19.762	116.753
	< 2 min	408	0.000	4.827	29.432
	2 – 20 min		0.000	0.000	-
	1 hour	1320	0.000	17.251	113.843
	4 hours	658	0.000	33.860	116.753
	8 hours		0.000	0.000	-
	More than 8 hrs		0.000	0.000	-
1996-2000	All duration	3501	0.000	27.613	124.958
	< 2 min	651	0.000	6.325	32.312
	2 – 20 min		0.000	0.000	-
	1 hour	1402	0.000	15.399	89.362
	4 hours	1202	0.000	51.692	129.254
	8 hours	117	0.000	89.885	189.605
	More than 8 hrs	129	0.000	0.000	-
2001-2002	All duration	1135	0.000	15.491	47.255
	< 2 min	200	0.000	13.817	13.817
	2 – 20 min	225	0.000	15.917	15.917
	1 hour	232	0.000	27.911	27.911
	4 hours	237	0.000	26.805	26.805
	8 hours	241	0.000	47.255	47.255
	More than 8 hrs		0.000	0.000	-

Table 5 – Small-Medium Commercial and Industrial Outage Costs by Duration and Years

Small-Medium Commercial and Industrial Outage Costs by Duration and Years					
Total Cost/Event					
	Duration	**N**	**Min**	**Average**	**Max**
All years	All duration	23800	0.000	2,734.865	105,224.660
	< 2 min	3209	0.000	893.241	105,224.660
	2 – 20 min	766	0.000	899.871	75,000.000
	1 hour	11829	0.000	1,901.498	105,224.660
	4 hours	5836	0.000	4,220.441	104,549.000
	8 hours	1319	0.000	7,361.290	104,493.208
	More than 8 hrs	841	0.000	5,590.039	86,393.089
Before 1990	All duration	1650	0.000	3,190.202	101,161.103
	< 2 min				
	2 – 20 min	413	0.000	831.116	50,798.258
	1 hour	827	0.000	3,124.343	101,161.103
	4 hours				
	8 hours	410	0.000	5,699.391	101,161.103
	More than 8 hrs				
1990-1995	All duration	1349	0.000	4,472.232	100,373.599
	< 2 min	10	0.000	18,749.689	93,623.910
	2 – 20 min				
	1 hour	898	0.000	3,282.512	100,373.599
	4 hours	441	0.000	6,571.086	97,833.554
	8 hours				
	More than 8 hrs				
1996-2000	All duration	18787	0.000	2,590.428	105,224.660
	< 2 min	1944	0.000	862.940	105,224.660
	2 – 20 min				
	1 hour	9689	0.000	1,691.935	105,224.660
	4 hours	4909	0.000	4,140.113	104,549.000
	8 hours	404	0.000	11,652.692	104,493.208
	More than 8 hrs	841	0.000	5,590.039	86,393.089
2001-2002	All duration	2014	0.000	2,544.452	100,200.000
	< 2 min	255	1.000	542.816	20,000.000
	2 – 20 min	353	1.000	980.312	75,000.000
	1 hour	415	1.000	1,369.007	75,000.000
	4 hours	486	1.000	2,898.829	75,000.000
	8 hours	505	1.000	5,277.434	100,200.000
	More than 8 hrs				

Small-Medium Commercial and Industrial Outage Costs by Duration and Years					
Cost Per Annual kWh					
	Duration	**N**	**Min**	**Average**	**Max**
All years	All duration	23800	0.0000	0.0218	0.1124
	< 2 min	3209	0.0000	0.0074	0.1124
	2 – 20 min	766	0.0000	0.0046	0.0812
	1 hour	11829	0.0000	0.0159	0.1124
	4 hours	5836	0.0000	0.0368	0.1117
	8 hours	1319	0.0000	0.0431	0.1131
	More than 8 hrs	841	0.0000	0.0408	0.0936
Before 1990	All duration	1650	0.0000	0.0154	0.1095
	< 2 min		0.0000	0.0000	0.0000
	2 – 20 min	413	0.0000	0.0040	0.0550
	1 hour	827	0.0000	0.0151	0.1095
	4 hours		0.0000	0.0000	0.0000
	8 hours	410	0.0000	0.0276	0.1095
	More than 8 hrs		0.0000	0.0000	0.0000
1990-1995	All duration	1349	0.0000	0.0321	0.1083
	< 2 min	10	0.0000	0.0607	0.1431
	2 – 20 min		0.0000	0.0000	0.0000
	1 hour	898	0.0000	0.0238	0.1083
	4 hours	441	0.0000	0.0476	0.1055
	8 hours		0.0000	0.0000	0.000
	More than 8 hrs		0.0000	0.0000	0.0000
1996-2000	All duration	18787	0.0000	0.0242	0.1124
	< 2 min	1944	0.0000	0.0081	0.1124
	2 – 20 min		0.0000	0.0000	0.0000
	1 hour	9689	0.0000	0.0159	0.1124
	4 hours	4909	0.0000	0.0402	0.1117
	8 hours	404	0.0000	0.1140	0.1150
	More than 8 hrs	841	0.0000	0.0408	0.0936
2001-2002	All duration	2014	0.0000	0.0133	0.1103
	< 2 min	255	0.0000	0.0028	0.0220
	2 – 20 min	353	0.0000	0.0051	0.0825
	1 hour	415	0.0000	0.0072	0.0825
	4 hours	486	0.0000	0.0151	0.0825
	8 hours	505	0.0000	0.0276	0.1103
	More than 8 hrs		0.0000	0.0000	0.0000

Small-Medium Commercial and Industrial Outage Costs by Duration and Years					
Cost Per Peak kW					
	Duration	**N**	**Min**	**Average**	**Max**
All years	All duration	23800	0.000	54.989	169.444
	< 2 min	3209	0.000	21.354	182.050
	2 – 20 min	766	0.000	8.553	120.773
	1 hour	11829	0.000	40.623	169.444
	4 hours	5836	0.000	91.631	180.882
	8 hours	1319	0.000	100.105	168.266
	More than 8 hrs	841	0.000	0.000	-
Before 1990	All duration	1650	0.000	34.832	162.900
	< 2 min		0.000	0.000	-
	2 – 20 min	413	0.000	9.075	81.801
	1 hour	827	0.000	34.113	162.900
	4 hours		0.000	0.000	-
	8 hours	410	0.000	62.229	162.900
	More than 8 hrs		0.000	0.000	-
1990-1995	All duration	1349	0.000	79.121	194.522
	< 2 min	10	0.000	127.203	216.722
	2 – 20 min		0.000	0.000	-
	1 hour	898	0.000	58.774	194.522
	4 hours	441	0.000	117.657	189.600
	8 hours		0.000	0.000	-
	More than 8 hrs		0.000	0.000	-
1996-2000	All duration	18787	0.000	67.111	182.682
	< 2 min	1944	0.000	24.280	207.135
	2 – 20 min		0.000	0.000	-
	1 hour	9689	0.000	47.607	190.280
	4 hours	4909	0.000	96.820	181.510
	8 hours	404	0.000	258.907	188.957
	More than 8 hrs	841	0.000	0.000	-
2001-2002	All duration	2014	0.014	7.919	173.356
	< 2 min	255	0.014	1.689	34.602
	2 – 20 min	353	0.014	3.050	129.758
	1 hour	415	0.014	4.259	129.758
	4 hours	486	0.014	9.018	129.758
	8 hours	505	0.014	16.419	173.356
	More than 8 hrs		0.000	0.000	-

The results from the analysis of the different tables above show a very clear trend in the effect of the outage duration on the outage costs.

The cost increases with the increase in the outage interruption until it reaches a value typically between 4 and 8 hours. After that it may stabilize or in some cases even decline. The chart also indicates that significant savings can be made if the outage duration if reduced from 1 hour to less than 2 minutes, in this case $40,000 on average.

The chart below is from the average costs of all surveyed outages for large commercial and industrial customers.

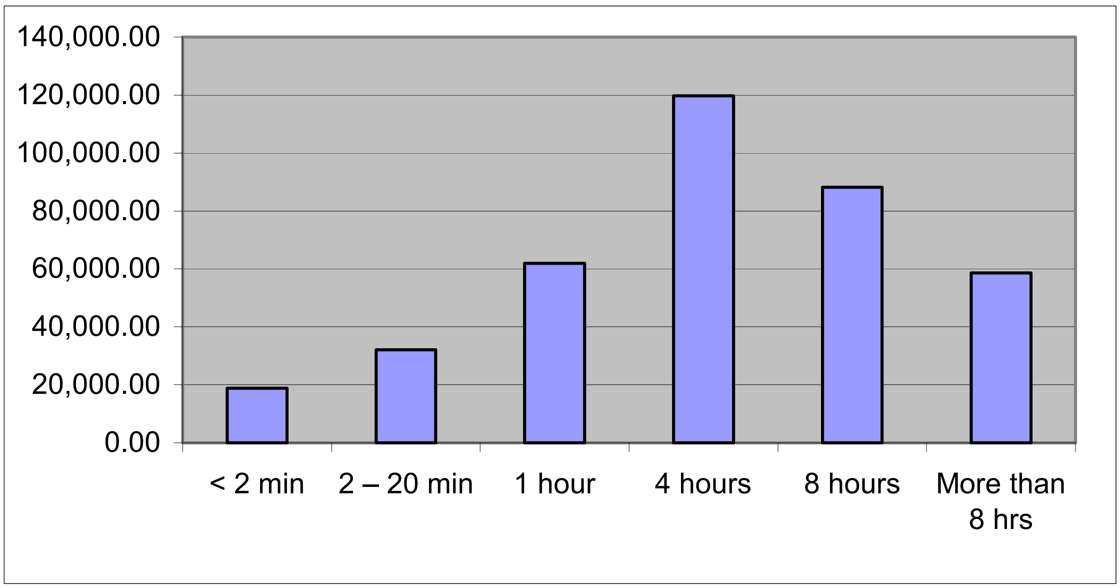

Figure 5 – Average Cost of Surveyed Outages by Duration

Data from other surveys and research is summarized below.

ASCO Power Solutions Newsletter

The following table is from the ASCO Power Solutions newsletter.

Table 6 – Outage Costs Per Industry

Industry	Average Cost of Downtime (per hour)
Cellular Communications	$41,000
Telephone Ticket Sales	$72,000
Airline Reservations	$90,000
Credit Card Operations	$2.58 million
Brokerage Operations	$6.48 million
Source: ASCO Power Solutions' newsletter.	

EdF Case Study

At EdF, the values used in the studies to economically justify investment to improve network reliability are:

- Cost of an interrupted kilowatt-hour: FRF60 (US$8) up to 30 interrupted MWh; FRF130 (US$17.4) for more than 50 interrupted MWh (Note: linear interpolation of costs between 30 and 50 MWh).
- Cost of an interrupted kilowatt: FRF5 (US$0.67).

ESource Survey

E SOURCE, an energy information company headquartered in Boulder, CO, recently polled more than 800 commercial and industrial customers within the health care, financial services, retail, grocery, agriculture, and manufacturing industries. The poll allowed those companies to define what constituted a damaging outage for their businesses. They reported an average of nearly 15 outages during a 12-month period, far more than most utilities would likely report, and the total cost of these outages came to more than $7 billion per year. This averages out to $583,333 per event.

IEEE 493-1997

The following is from the IEEE standard 493-1997.

For industrial plants, the average cost of a single power interruption is $6.43/kW + $9.11/kWhr.

For commercial facilities, the average cost of a single power interruption is $21.77/kWhr not delivered.

Costs based on duration with office buildings containing computers.

15 minute duration – $26.85 average cost per peak kWhr not delivered

1 hour duration - $25.07 average cost per peak kWhr not delivered

> 1 hour duration - $29.63 average cost per peak kWhr not delivered

EPRI/CEIDS Survey

CEIDS found that the average cost of a one hour outage to industrial and digital economy establishments was $7,795. A three minute outage cost $2,107. A one second outage cost $1,477. For continuous process manufacturing, the outage costs were $12,654, $18,476, $14,746 for a 1 second, 3 minute and 1 hour outage. For fabrication and essential services, the outage costs were below the continuous process manufacturing costs. Total average annual cost in US for zero voltage events was $23,318.

Survey found that costs went up significantly based on size of the establishment. The average cost of an outage to an establishment greater than 5 GWhr was nearly $60,000 for a one hour outage.

Primen Massachusetts Survey

Primen surveyed 19 businesses in Massachusetts. They found that the average cost for a 1 second outage was $4,833, the cost of a 1 hour outage was $21,688 and the annual costs were just under $122,000. They stated that the results were skewed by the limited number of respondents. In another section of the report they stated that in Massachusetts, the average annual cost in for zero voltage events was $24,393, basically the national average as found by the CEIDS survey.

ICF Consulting

Analyses done by ICF consulting have concluded that one method to calculate the cost of outages is to determine what the customer is willing to pay to avoid such outages. They found that this value is in the range of 80 to 120 times the retail price of electricity.

Summary

The following table summarizes all of the data collected during the study from the various sources.

Table 7 – Summary Table of All Outage Cost Studies

	Average cost per hour	Cost per kW / kWh	Cost per event
Population Research Systems	$61949 for large industrial and commercial All Regions - $59,983 Northwest - $28,609 Southwest - $51,908 Southeast – $86,477 West - $52,734 Midwest - $28,735		
ASCO	Cellular 41k Telephone 72K Airline reservation 90k		
EDF		0.67 / kW $8/kWh up to 30 MWh $17.4/kWh from 30 to 50 MWh (linear interpolation)	
ESOURCE			$583k over 800 commercial and industrial customer over 1 year
IEEE 493-1997		Industrial - $6.43 /kW and $9.11 / kWh Commercial - $21.77/ kWh Computer based business	
CEIDS EPRI	$7795 for digital establishments $14746 for continuous process manufacturing		
Primen Mass Survey	$21688 for 19 businesses surveyed		
ICF Consulting			80 to 100 times the cost of retail electricity

The bulk of the data was from US utilities. In looking at the different regions from the US, there is quite a difference as was pointed out earlier. It was hard to ascertain from the surveys why this was so, but our assumption was that the numbers from the Northeast would be a good approximation given the geographic proximity and similar weather patterns. We've found several sources that said that cost of business in Canada is 9% cheaper than in the US. So you could argue that the US figures given are 9% higher than what they would be for Canada.

6. Methods to Reduce Outage Costs

Consumer outage costs can be significantly reduced by considering the effect of the different factors and taking measures to implement solutions that will result in minimal losses in the event of power interruption.

Implementing emergency actions strategy

Remote monitoring and control

Event driven maintenance

Reclosing

Fuse saving schemes

Adaptive protection

Crew training

Dynamic loading

Outage forecasting

Standby systems

Implementing emergency actions strategy

One method that can be used to reduce outage costs is the implementation of emergency actions strategy.

The use of emergency actions strategy plays a significant role in curtailing the consumer outage costs ensuing from unreliable electric service. In order to calculate the savings in outage costs, the probabilistic framework of the frequency and duration method has been used in conjunction with emergency actions.

Comparison of the outage costs of various consumer sectors that are estimated without considering any emergency actions with the consumer outage costs calculated by combining the frequency and duration method with the emergency actions invoked demonstrates the advantages of the second approach.

Study results show that substantial savings in consumer outage costs are obtained by devising and implementing emergency actions strategy in situations of capacity outages.

The results are of particular relevance to utilities with constant or temporary shortage of capacity. They also apply to underdeveloped and developing countries where capacity shortages occur quite frequently.

Remote monitoring and control

The impact of remote controlled disconnectors and automatic sectionalizing devices can be significant on the overall duration of outages in a typical rural and semi-rural area overhead MV system.

Optimal switching can reduce the overall outage cost by providing power to more sensitive customers. This requires the availability of sufficient data to achieve the optimal solution based on the types of loads, the power demand, system configuration and other factors that affect the outage costs. Most of this data is available through remote monitoring, that represents the first part of such solution.

The second part is the remote control of the switching devices. Especially in rural areas it may be very difficult and it will take a while to perform the optimal switching required by the method.

The optimization technique in this case needs to determine:

(1) number of remotely controlled sectionalizing switches

(2) locations of the remotely controlled switches

Such methodology can offer a global optimal solution for the remotely controlled sectionalizing device placement problem which includes the reliability, investment and maintenance costs.

Event driven maintenance

As can be seen from the chart in the section on cause of outages, 37% of outages are the result of equipment failure. The obvious conclusion is that if a utility or an industrial facility can reduce the number of equipment failures, especially breakers, switches, transformers and other devices related to power production and delivery.

A method that allows significant reduction of equipment failure is improved maintenance. Scheduled maintenance is very expensive, since it requires significant resources and time, as well as it creates scheduled outages. There are also cases when equipment fails as a result of human errors during the maintenance.

A more efficient way of doing maintenance is “event driven” maintenance. Many Intelligent Electronic Devices installed in substations have built-in functions that can be used to alarm when a primary device needs maintenance, before it fails. For example, by monitoring the number of breaker trips, the sum of the interrupted fault current during the tripping of short circuit faults or the time that it takes for the breaker to trip, the device can alert that future failure is possible and maintenance is needed.

Even though such event driven maintenance will require a scheduled outage, from the report it is clear that when an outage is scheduled and the customers have received a notice in advance, the outage costs are significantly reduced or eliminated. At the same time the probability for an unscheduled outage and the significant losses that it may result in is significantly reduced.

Reclosing

Since any short circuit fault on the transmission, sub-transmission and distribution lines always result in an interruption after the breaker trips to clear the fault, appropriate use of auto-reclosing can significantly reduce the outage costs by reducing the duration or eliminating long outages.

At the transmission level in the case where communications based protection is used such as line differential, directional comparison, phase comparison or different distance communication based schemes, it is possible to implement high-speed reclosing. This will result into significant reduction of the duration of a potential outage and since most faults are temporary, successful reclosing will restore the power after a short interruption.

Implementing single pole trip and reclosing further reduces the effect of a fault on sensitive customers, because only the faulted phase is open during the reclosing cycle. As a result, there is still power flow through the circuit, even though it is unbalanced.

The implementation of reclosing at the distribution level can have a much more significant effect on the reduction of outage costs. It can be achieved using two approaches:

- Increased number of reclosing shots
- Reduced duration of the reclosing dead time

Most temporary faults are usually cleared after the first trip and the outage ends after successful reclosing.

Second and third reclosing shots further improves the chances of clearing a fault and avoiding a prolonged outage and high losses.

The duration of the reclosing dead intervals can also be improved. For example, many utilities use a 120 second setting for the third reclosing shot. Analysis and reevaluation of this setting can lead to a shortening of this setting and thus reducing the outage duration and the related outage costs.

Fuse saving schemes

Distribution feeders are used to supply power to multiple customers through distribution transformers, typically protected by fuses. The reason is that this is an inexpensive way of protecting the transformers, and since short circuit faults do not occur very often, it is widely implemented.

The problem with fuse protection is that it does not allow automatic restoration of the power supply and also requires a crew to be sent to the location to replace the fuse, which can lead to a significantly long supply interruption and high outage costs.

Considering the fact that most short circuit faults have a temporary nature, attempting to clear the fault before the fuse blows has become a standard practice in many utilities.

This is achieved by applying a Fuse Saving Scheme. The idea is to use a low-set instantaneous overcurrent element to trip the breaker in the substation immediately after the fault occurs. This obviously means that there is no coordination of the instantaneous overcurrent element with the downstream fuses. The breaker is tripped before the fuse protecting the faulted section of the feeder (or a distribution transformer) melts. After the reclosing the low set instantaneous element is disabled and a high-set instantaneous, as well as a time-overcurrent element that both coordinate with the downstream protective devices are used.

This method has some advantages and disadvantages that have to be considered before making a decision to apply the Fuse Saving Scheme in an attempt to reduce outage costs.

The advantage is that in case of a temporary fault the fuse is not going to melt, i.e. it will not require a replacement and will result only in a short interruption of the load during the dead interval of the reclosing sequence. This can be very important, especially in cases where the fuse is at a remote location, and under difficult meteorological conditions, when it will take a long time for the crew to get to the location and replace the fuse.

The disadvantage is that all the customers supplied from the feeder will be affected by the interruption during the reclosing cycle. That is why the decision to apply the Fuse Saving Scheme should be made based on the type of load connected to the feeder and the expected outage costs for a short interruption.

Adaptive protection

The protective relays are designed and set to clear faults under different fault or other abnormal system conditions. In some cases this is a very difficult task, since it may be impossible to calculate a setting that will clear a line end high-impedance fault but will not operate for the inrush condition when the distribution feeder breaker is closed.

Another problem is the setting of ground overcurrent relays that will behave in a different way depending on the grounding of the transformer connected to the distribution bus. As a result, some distribution feeder faults may be cleared by a backup protection relay on the high side of the transformer, thus leading to an outage for all customers supplied by the distribution substation.

The number and duration of such outages can be reduced by the implementation of adaptive protection. The protective relay in this case monitors the substation configuration or receives signals for changes in the system configuration and adapts to the new system conditions using two typical methods:

- Change of setting group
- Programmable Scheme Logic

Adapting to the new conditions reduces the chances that the relay may fail to trip when required or trip unnecessary. As a result the number and duration of outages will be reduced.

Dynamic loading

Outages that are the result of insufficient capacity can be avoided, or their duration can be reduced if the transformer, transmission line or other electric power system equipment can be dynamically loaded above their nameplate rating.

This is achievable by monitoring the different parameters that affect the overheating of the transformer or line.

Thermal overloading monitoring functions based on different algorithms and measurements available in modern multifunctional protection and control devices, as well as specialized monitoring devices, are used to allow the dynamic loading of system equipment. As a result, shedding of load to reduce the loading is not required at least for a certain amount of time, thus reducing the duration of an outage.

The figure below shows the big difference between the normal, emergency and dynamic loading of a transmission line.

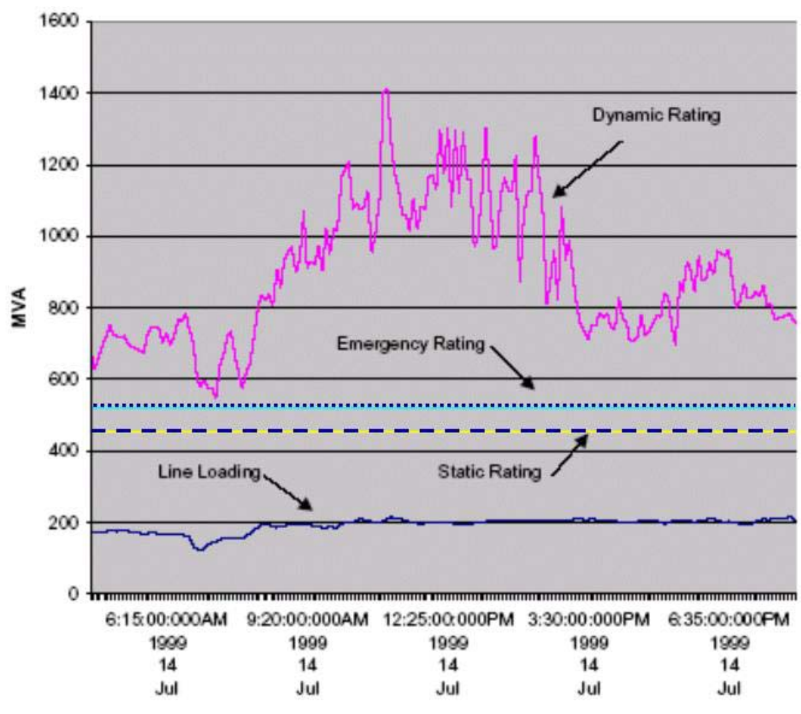

Figure 6 – Differences Between Normal, Emergency and Dynamic Loading of a Transmission Line

An even more important result of the delay in load reduction is the fact that this allows sensitive customers to be notified about the coming outage, which will allow them to shut down critical processes and trip non-essential loads. This will minimize the cost of the outage to the customer.

It is very important to properly select the type of protection of electric power system elements that are subject to dynamic loading in order to prevent the tripping by the protection device that is not properly configured to accommodate the dynamic loading.

Outage forecasting

The analysis of the cost of outages in the previous sections of this report showed that if a customer receives in advance a notice that an outage will occur at a specific time, they can take action to reduce the consequences of the load interruption.

Notification is typically available in the cases when the outage is scheduled. Predicting that an outage may occur will bring the same benefits as the ones described above.

Forecasting that an outage may occur can be done using:

- short-term load forecasting
- system configuration information
- data about the dynamic loading capabilities of the available equipment
- system state estimator
- protection settings
- remedial action schemes settings

Once the outage forecasting system detects high probability and the characteristics of a predicted outage, it can automatically send notification to customers participating in the system to prepare for the outage, thus reducing the overall outage cost.

Crew training

Crew training can also reduce the outage costs by shortening the outage duration.

There are several aspects of this process. The first is reducing the time it takes to find the cause of the outage. This requires a lot of experience, excellent knowledge of the electric power system and sufficient information about the outage.

Since many utilities are continuously losing experienced and knowledgeable employees, it is important to train the new engineers and technicians in order to speed-up and improve the accuracy of the fault location estimation.

Once the location of the fault or other event that caused the outage is known, it has to be fixed. This time is dependent on the quality of the crew that will perform the required actions to restore the service to the customers.

It is obvious that highly trained crews will take less time to fix a problem, compared to less experienced crews.

Standby systems

The analysis of the different factors that affect the reliability of the power supply and the cost of outages demonstrate that the losses are significantly reduced when the customer has standby systems available during the outage.

Standby systems, however, have a price tag. That is why it is very important to determine through cost/benefit analysis the parameters of such systems.

One solution that can be implemented at a regional or local level is the availability of a set of mobile standby systems.

Since in many cases a fault is the result of equipment failure at a specific location, a mobile transformer, breaker or generator can be moved to the site where the failure occurred, in order to replace the equipment that is out-of-service for the duration of an outage.

In an effort to improve service reliability, and especially to reduce the duration of outages, some utilities are implementing a new method. As soon as there is an outage, a mobile standby system or unit is sent to the site and put in service immediately. At the same time the investigation of the cause of the outage and the process of restoring the failed equipment or circuit is initiated.

As a result, a very significant reduction of outage costs can be achieved for a much lower cost than the installation of fixed standby systems at each customer location.

7. Customer Attitude

Regarding Electric Outage Costs and Back-up Generation

Market research is used to determine whether a substantial market exists for an utility to sell, operate, and/or maintain backup generators for a profit, and the estimated outage costs predicted in value-of-service mail surveys (VOSS) used to indicate of the investment customers would make to avoid outages.

The results show that, when a more detailed investigation is performed on-site with customers who had indicated perceived outage costs exceeding the costs of owning and maintaining a back-up generator (approximately $30/kW-yr), outage costs estimates are substantially lower and dropped to $0 in 40% of the cases.

It is concluded that customers had difficulty quantifying effects of hypothetical outages, and most customers expect no future outages, even though outages occurred regularly in the past.

Although the number of surveys completed do not constitute a statistically valid sample, the following points became clear through the interviews:

- The outage costs calculated in different Value of Service Studies appear to grossly overestimate the actual willingness for a customer to pay to avoid an outage through use of a back-up generator.
- Meeting directly with the customer at the premise could substantially increase the accuracy of predicted outage costs compared to mail or telephone surveys.
- Most customers find it difficult to accurately predict outcomes of a failure or hypothetical outage, and many customers do not expect a future outage.
- Even if there is a positive cash flow potential when installing a back-up generator, customers cite many reasons for not making the capital investment, including capital priority, return on investment criteria, and installation difficulties.
- Most customers are content with their current level of reliability. If reliability worsened, customers' predicted outage costs would become greater.
- Interest in purchasing a back-up generator generally relied upon a substantial rate decrease through participation in an interruptible or curtailable service option, as opposed to only eliminating outage costs.
- Future studies to find the value of reliability should consider using the alternate investment approach (i.e. offering nearly perfect reliability through insurance or a back-up generator) to obtain more accurate results, given that it meets the overall planning objectives.
- Outage costs obtained immediately after an actual outage could provide increased accuracy if used in conjunction with those derived from a hypothetical scenario.

- In some applications, back-up generation in conjunction with an interruptible rate could be a more favorable alternative to both the customer and utility than co-generation.

The customer interruption costs (CIC), as a result of interruptions in their electricity supply are considered key indicators of customer expectations and therefore of reliability worth.

The following figures show the results from surveys on customer attitudes towards outages. The question asked in the survey is included in the charts shown below.

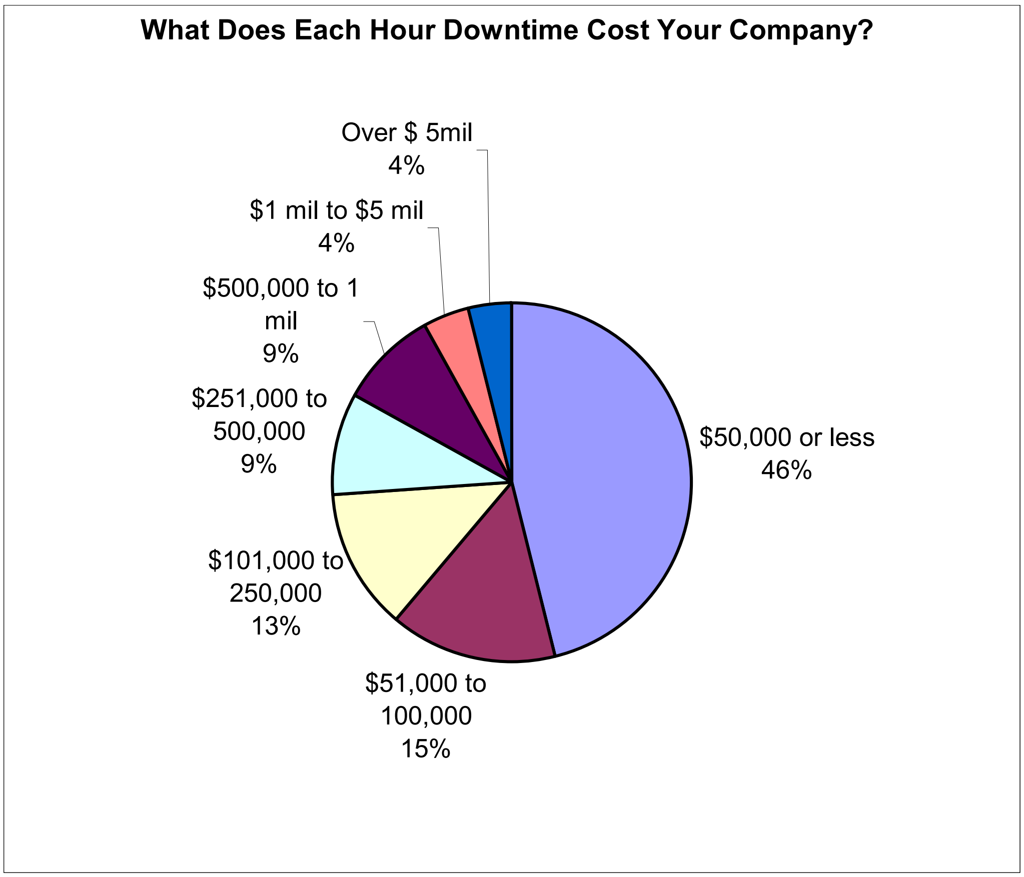

Figure 7 – Costs of 1 Hour of Downtime

The cost of the downtime for about 45 percent of the customers is less than 50 thousand dollars /hour.

Another 37 percent are in the range from 50 thousand/hour to 500 thousand dollars /hour.

Only about 4 percent experience losses of more than 5 million dollars /hour.

It is clear from the chart above that with such outage costs, and considering the fact that the cost of the outage typically increases with the increase of outage duration, long outages may result in the failure of the company.

The following chart shows the outage duration that may lead to such failure.

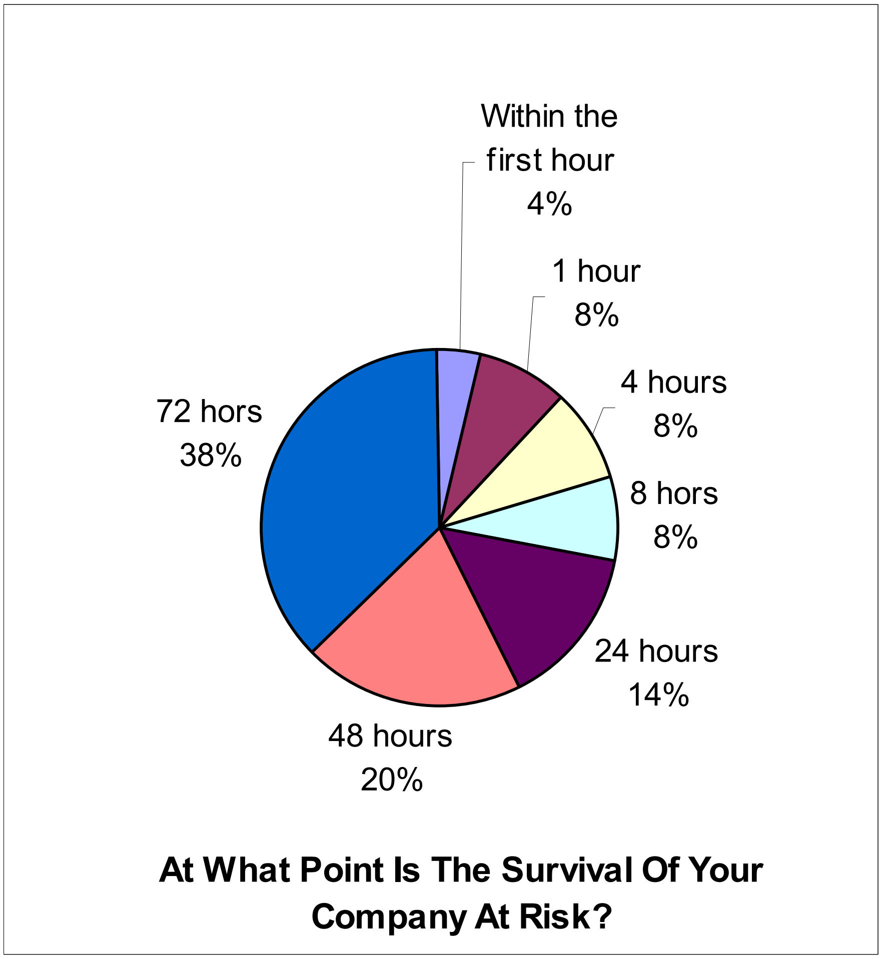

Figure 8 – Company Risk Profile

The attitude of customers towards outages and utilities efforts to reduce the outage costs is well represented by the customer's willingness to pay for improved reliability.

The table below gives the minimum, average and maximum numbers for the different regions in the US [64] for residential customer's willingness to pay.

Table 8 – Residential Willingness to Pay

Residential Willingness-To-Pay				
Region	**N**	**Min**	**Average**	**Max**
All regions	11200	0.000	6.82	56.05
Northwest	2243	0.000	7.60	43.54
Southwest	4380	0.000	7.02	53.25
Southeast	3903	0.000	7.17	56.05
West	674	0.000	2.26	53.25
Midwest				

The attitudes towards improved reliability and the associated outage costs also changes with time and is affected by the customer experience in recent outages.

The table below show the residential customers willingness to pay by duration and years.

Table 9 – Residential Willingness to Pay Vs Duration

Residential Willingness-To-Pay					
	Duration	**N**	**Min**	**Average**	**Max**
All years	All duration	28042	0.000	6.493	62.696
	< 2 min	4210	0.000	4.383	56.054
	1 hour	14746	0.000	6.642	56.054
	4 hours	7242	0.000	7.155	62.696
	8 hours	1637	0.000	5.155	62.696
	More than 8 hrs	207	10.799	26.268	53.996
Before 1990	All duration	1927	0.000	3.869	58.055
	< 2 min				
	1 hour	960	0.000	2.461	43.541
	4 hours				
	8 hours	967	0.000	5.267	58.055
	More than 8 hrs				
1990-1995	All duration	3115	0.013	6.273	62.267
	< 2 min	911	0.013	4.527	37.360
	1 hour	1433	0.062	6.450	49.813
	4 hours	771	0.062	8.008	62.267
	8 hours				
	More than 8 hrs				
1996-2000	All duration	23000	0.000	6.743	62.696
	< 2 min	3299	0.000	4.343	56.054
	1 hour	12353	0.000	6.989	56.054
	4 hours	6471	0.000	7.053	62.696
	8 hours	670	0.000	4.993	62.696
	More than 8 hrs	207	10.799	26.268	53.996

8. Use of Outage Costs

The structure of electric utilities is undergoing dramatic changes as new and expanded service options are added. The concepts of unbundling the electric service and offering customers a range of new services that more closely track actual costs are expanding the options open to customers.

Spot pricing provides the economic structure for many of these new service options. An important component of spot prices is the marginal outage cost incurred by customers due to an incremental change in load.

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Quantitative evaluation of savings in outage costs by using emergency actions strategy

This paper presents the results of a study carried out to assess the savings in consumer outage costs that can be accrued as a result of implementing emergency actions strategy.

The use of emergency actions strategy plays a significant role in curtailing the consumer outage costs ensuing from unreliable electric service. In order to calculate the savings in outage costs, the probabilistic framework of the frequency and duration method has been used in conjunction with emergency actions.

At first, the outage costs of various consumer sectors are estimated without considering the emergency actions.

Secondly, the consumer outage costs are calculated by combining the frequency and duration method, and unserved energy with the emergency actions invoked.

The results of the savings in consumer outage costs that can be accrued by utilising emergency actions strategy are presented for a synthetic system. The results of the study show that substantial savings in consumer outage costs are obtained by devising and implementing emergency actions strategy in situations of capacity outages.

The results are of particular relevance and utility to the underdeveloped and developing countries where capacity shortages occur quite frequently. These results also suggest the importance of emergency actions strategy for electric utilities in reducing the consumer economic losses arising from unreliable electric service

Development of an analytical method for outage cost assessment in a composite power system

This study proposes a new analytical method for assessing the outage cost of a composite generation and transmission system. Outages of the generation system and the transmission system were included in this study.

First, the composite power system effective load duration curve ELDC (CMELDC) at HLII was developed from reliability evaluation of the composite power system in order to assess the outage cost at HLII.

Secondly, mathematical expressions for the marginal outage cost function at each load point are formulated using relations between GNP (or GDP) and the electrical energy demand.

Finally, the outage cost is calculated by combining the proposed CMELDC with the marginal outage cost function at each load point. The effectiveness of the proposed approach is demonstrated by the IEEE-RTS

Customer attitudes regarding electric outage costs and back-up generation

A market research project was conducted to determine whether: a substantial market exists for PG&E (Pacific Gas and Electric) to sell, operate, and/or maintain backup generators for a profit, and the estimated outage costs predicted in a previous value-of-service mail survey (VOSS) were indicative of the investment customers would make to avoid outages.

The results showed that, when a more detailed investigation was performed on-site with customers who had indicated perceived outage costs exceeding the costs of owning and maintaining a back-up generator (approximately $30/kW-yr), outage costs estimates were substantially lower and dropped to $0 in 40% of the cases.

It is concluded that customers had difficulty quantifying effects of hypothetical outages, and most customers expect no future outages, even though outages occurred regularly in the past

Evaluation of the marginal outage costs in interconnected and composite power systems

The structure of electric utilities is undergoing dramatic changes as new and expanded service options are added. The concepts of unbundling the electric service and offering customers a range of new services that more closely track actual costs are expanding the options open to customers.

Spot pricing provides the economic structure for many of these new service options. An important component of spot prices is the marginal outage cost incurred by customers due to an incremental change in load.

This paper presents a formalized approach of calculating the marginal outage cost in interconnected generating systems and composite generation and transmission systems using quantitative reliability techniques. The effects of selected pertinent factors on the marginal outage cost in composite systems are also presented.

The proposed methods are illustrated by application to the IEEE-Reliability Test System (IEEE-RTS)

Understanding commercial losses resulting from electric service interruptions

A summary of research conducted to determine the effect of outage costs on commercial consumers having electric standby systems and to identify customer related and interruption related variables that affect the losses is presented.

It is shown that consumption and demand normalized outage costs for users having no standby systems are higher typically by three times when compared with users having standby systems. No significant differences were observed between battery and engine-driven standby systems.

Variation in outage costs with respondent category was studied. Respondents indicated that they could make significant cost savings arrangements if provided with advance warning or duration information of the interruption. 45% of all respondents having standby systems indicated there were health or safety hazards due to interruptions

Evaluation of the marginal outage costs of generating systems for the purposes of spot pricing

This paper describes a methodology based on quantitative power system reliability evaluation for calculating the marginal outage costs of generating systems. The proposed method involves the calculation of the incremental expected unserved energy at a given operating reserve level and lead time and the multiplication of this value by the interrupted energy assessment rate of the system.

The method is illustrated in this paper by calculating the marginal outage cost profile of the IEEE-Reliability Test System and by examining the effect of various modelling assumptions on that profile

Comparison of alternative techniques for evaluating the marginal outage costs of generating systems

Quantitative evaluation of the marginal outage costs associated with generating systems involves, among other things, the construction of a model of the system capacity outages. This model is inherently discrete and application of the well-known and basic recursive technique requires lengthy computations when applied to large power systems. Alternatively, continuous distributions and fast Fourier transforms can be used to approximate the generating system capacity model.

These techniques can in some cases introduce inaccuracies in the results, which depend on the system under consideration. Several authors have used these approximate techniques in the calculation of capacity outage probabilities, the study of parameter uncertainty in generating capacity reliability evaluation, the calculation of the expected energy production costs and the maintenance scheduling of generating facilities.

This paper discusses the potential application of the approximate techniques in the evaluation of the marginal outage costs of a power system.

The results of the approximate techniques are illustrated by comparison with those produced by the exact recursive technique for the IEEE-Reliability Test System

Comparison of the methods for assessing the customers' outage costs

This paper gives a comparative study of various methods for assessing the customers' outage costs. The methods considered are the willingness to pay in order to avoid an outage, the willingness to accept compensation for having had an outage, the customer survey where the costs are estimated directly by the customers themselves and an econometric model based on price elasticity. In the case of industrial customers, also the correlation between the outage costs and the value added by the production is examined.

The use of different methods is illustrated by the main results of a large Nordic study, carried out in 1992 and 1993

Evaluation of the marginal outage costs in interconnected generating systems

This paper describes a methodology for calculating the marginal outage costs in interconnected generating systems. The proposed method quantifies the impact of capacity assistance from neighboring systems on the marginal outage cost.

The effect of selected interconnection topologies and modeling assumptions on these costs is also presented in order to illustrate how simplified representations can be used to approximate the results obtained using more detailed reliability models

Value of service reliability

The authors present the value of service (VOS) reliability evaluation approach, which explicitly incorporates into the planning process customer choices regarding reliability `worth' and service costs. Using the least-cost planning framework and taking advantage of the recent advances in the quantification of outage costs, this approach determines the optimal level of reliability for the utility and its customers.

The approach considers system operational measures-the so-called emergency actions-that the operators invoke in times of dwindling reserves. Information on customer outage costs associated with such actions is incorporated using a probabilistic framework. This approach permits utilities to plan for levels of reliability commensurate with the customers' willingness to pay.

The application of this methodology to planning problems is discussed. Numerical results for a large utility are presented

A practical approach for estimating future outage costs in power distribution networks

Quantitative reliability analysis is integrated as a part of a distribution network information and design system. The outage rates, outage durations and costs of outages are evaluated using the data included in the network database together with the reliability data for network components and the per unit values for the energy not supplied.

Using the reliability calculation program together with other programs, optimum development plans for each network can be studied. In these studies, both the technical restrictions and the total costs, including the costs of investments, losses, and outages, must be included

Developing marginal costs for real-time pricing

The authors describe an approach for forecasting day-ahead hourly costs for real-time pricing of electricity. Marginal costs have two components, marginal operating costs, and marginal outage costs. The approach for estimating marginal operating costs is a modification of techniques developed for security constrained dispatch.

The approach for marginal outage costs involves estimating the economic damages associated with outages as well as the load-related probability that an outage will occur. Data problems and procedures required for model validation are also addressed

Estimating customer outage costs due to a specific failure event

Customer interruption costs due to failure in electrical energy supply depend on many factors. A procedure is developed to estimate the customer outage costs on a distribution feeder subjected to a specific outage event.

The data required to perform a detailed evaluation is illustrated and discussed, including the customer composition on the feeder, the customer demand profiles at the feeder load points and the relevant customer damage functions.

The procedure presented in the paper is illustrated by application to a specific distribution feeder in the city of Saskatoon. The customer costs associated with power supply failures are a function of the time of day, day of the week and time of year. They are also strongly influenced by the duration of the outage event. The effect of outage duration and the time of outage occurrence is illustrated.

Factors affecting customer outage costs due to electric service interruptions

In the UK, the concept of reliability worth has been considered a factor in justifying power system reliability investment since the late 1970s.

Two specific considerations which have been developed are the ‘implied cost per kWh saved’, and the `value of lost load'. These considerations apply historical methods for the assessment of reliability worth which rely on placing a worth value to the ‘energy not supplied’. While the authors do not fault these applications, they are, however, of the opinion that placing a worth value to the ‘energy not supplied’ is an essential weakness of historical methods for evaluating the worth of reliability perceived by customers. To overcome this weakness, the authors have been conducting extensive surveys and studies to assess customer outage costs, these being considered as proxies of reliability worth.

As part of these studies, the authors have investigated the factors affecting customers' perceived costs caused by supply interruptions. The results show that, contrary to the relations inferred by the historical methods, customers are only concerned with the inability to use their equipment and the costs of likely damages when considering the costs of supply interruptions.

On the basis of these findings, the authors conclude that rather than evaluate the benefits of `reliability investment' to electricity customers by placing a worth value on the `energy not supplied', a method based on customers' actual valuation of these benefits is more appropriate

Applications of customer outage costs in system planning, design and operation

Although the basic function of an electric utility company is to supply power economically and at acceptable levels of continuity and quality, the emphasis placed on these aspects during planning, design and operation depends on the level of power system development.

Further development of developed power networks is dominated by technological changes and concern for strict economic operation, quality of service and reliability. The authors only address issues related to reliability and consider distribution systems which are a part of developed networks from this vantage point. It has been suggested that existing standards do not adequately address customers' concerns over reliability.

To redress this, the authors address such concerns by presenting customer outage costs (COC), which are considered as proxies for reliability worth, as a criterion for providing additional justification for alternative distribution system plans, designs or operating policies. To demonstrate the application in these respects, two distribution networks based on realistic 33 kV power systems are analyzed, and the effects of network modifications or changes in operating policies on traditional reliability indices and COC studied

Assessment of customer outage costs due to electric service interruptions: residential sector

The assessment of the benefit or worth of reliability is perceived as being a major contribution in providing the additional detail in the justification of new system facilities and operating reliability levels provided the required information can be obtained in a consistent and coherent manner.

The costs incurred by consumers, customer interruption costs (CIC), as a result of interruptions in their electricity supply are considered key indicators of customer expectations and therefore of reliability worth. The assessment of CIC through surveys is considered to yield the most definitive results. Since the worth of these factors is difficult to quantify, consistent convergence of respondents' opinions on issues related to the electricity service can be useful in lending credibility to the interruption costs derived from surveys.

The paper is based on extensive surveys conducted at UMIST. It reports on the customer characteristics of the residential respondents and their experience of interruptions, the undesirability of some effects of interruptions and the variation of undesirability of effects with frequency of interruption, season, time of day and weekday/weekend. The customers' ratings of these aspects are also tested for statistical correlation with the customer and experience of interruption variables. Agreement on the opinions is displayed across the RECs leading to the expectation that the corresponding CIC derived from the studies will be comparable as well

Customer outage cost evaluation of an actual failure event

The customer interruption cost when an electric supply failure occurs depends on many factors, such as the customer types interrupted the actual load demand at the time of the outage, the duration of the outage, the time of day and the day in which the outage occurs.

This paper illustrates the development of a procedure to perform customer outage cost evaluation on a distribution feeder subjected to a specific outage event. Data required to perform a complete evaluation is illustrated and discussed. This data includes the feeder customer compositions, the profiles at the feeder load points and the relevant customer damage functions.

The procedure presented in the paper is illustrated by application to a specific distribution feeder in the City of Saskatoon. The customer costs associated with power supply failures are a function of the time of the day, day of the week and time of the year. They are also strongly influenced by the duration of the outage event.

The paper illustrates the effect of outage duration and the time of outage occurrence.

Distributed nature of residential customer outage costs

Reliability worth assessment is an important factor in power system planning and operation. An equally important issue is how to use customer costs of electric supply interruptions as surrogates to appropriately quantify reliability worth. Postal or in-person surveys of electric customers are often used to determine interruption costs.

The results obtained from the surveys are transformed into customer damage functions which are applicable to individual customer classes and sectors. Standard customer damage functions use aggregate or average customer costs for selected outage durations. This paper develops a practical alternative to the customer damage function method of describing the interruption cost data. The alternate technique, which is designated as the probability distribution approach, is capable of recognizing the dispersed nature of the data.

The proposed probability distribution method is illustrated in this paper using the interruption cost data collected in a 1991 survey of the Canadian residential sector

Evaluation of reliability indices and outage costs in distribution systems

Reliability evaluation of distribution systems assesses the adequacy of the load points in regard to providing a suitable supply to customers. This area has received increased interest during the past few years. A considerable number of papers have been published describing the development and application of the available techniques for modelling the various features of a distribution system and for evaluating the reliability indices. Also a few publications have considered the evaluation of probability distributions of the reliability indices for radial systems.

However, due to the complexity of the analysis and the need to consider overlapping outages in meshed networks, these techniques are not able to evaluate the probability distributions for such networks. Also, further considerations are still required in the evaluation of interruption costs/reliability worth in order to obtain true and more realistic values that reflect the behaviour of the system under study.

This paper describes models and techniques for evaluating the probability distributions associated with the reliability indices in meshed networks. It also presents a procedure for combining costs of interruptions with the probability distributions of interruption durations and of CAIDI to assess the cost of interruptions in meshed networks.

The proposed approaches are based on a combination of analytical techniques and Monte Carlo simulation. Finally the paper reports on the results obtained from sensitivity studies developed for bus 1 of the IEEE Reliability Test System

Reliability differentiated real-time pricing of electricity

Optimal resource planning and power dispatch models (from a societal welfare point of view) imply an optimal pricing policy, which is referred to here as reliability differentiated real-time pricing or, in short, reliability differentiated pricing. This pricing scheme combines real-time pricing and priority pricing with reliability differentiation based on consumer outage costs. This pricing policy is analyzed.

The model used in the analysis is developed with particular emphasis on consumer behavior and welfare effects. The implications of the model for the pricing of spinning reserve and firm capacity, as well as for revenue reconciliation, are examined. It is concluded that such a pricing scheme will in general result in greater attainable welfare than either the real-time pricing or priority pricing paradigms.

Moreover, it results in the maximum attainable welfare for the system with revenue reconciliation and provides an optimal pricing scheme for spinning revenue and firm capacity

Engineering foundations for the determination of security costs

Power system security is characterized by using distances to system operational limits (including voltage collapse limits, stability limits, line and transformer overloads, and generator limits). It uses the point of collapse method based on the singularity of the power flow Jacobian to define an operational limit boundary in load demand space. Distances to this boundary are then translated into probabilistic measures of likelihood of system failure: probability of normal status, expected demand not served, expected unserved energy, and, ultimately, expected outage cost. Sensitivities of these measures to load and generation changes (important for operational decisions and real-time pricing) are also described. A numerical example is presented. Computational issues are discussed

Economics of energy reliability

The types of reliability considerations and the deterministic criteria currently used by most utilities for electric transmission reliability planning are outlined. The complex process of weighing outage costs against prevention costs in this approach is discussed. A probabilistic approach increasingly being adopted by electric utilities is described that allows costs and benefits of reliability to be compared directly.

Computing the value of security

Power systems are operated with some margin of security to ensure that the most likely losses of plant will not cause interruptions to supply. However, this security margin has a cost that may not be justified by the benefit in terms of prevention of lost load. The authors argue that the level of security could be set on the basis of a cost/benefit analysis that balances the cost of operating the system against the expected outage cost.

The expected outage cost is determined using a Monte Carlo simulation of the system operation in which random outages are simulated. Such a simulation should not be limited to small but relatively frequent outages but should also include major disturbances that affect a large part of the system. In order to achieve a sufficient degree of accuracy, the simulation models the actions taken to save the system during emergencies, the duration of the restoration process, and possible protection malfunctions.

It is shown that sympathetic trippings due to protection malfunction can have a very significant impact on the probability of major incidents and hence on the value of security.

Observed changes in residential and commercial customer interruption costs in the Pacific Northwest between 1989 and 1999

In 1989, the Electric Power Research Institute and Bonneville Power Administration conducted pioneering surveys of the interruption costs experienced by residential and commercial and industrial customers in the Pacific Northwest. In early 1999, Puget Sound Energy (PSE) surveyed its customers using statistical sampling techniques and outage cost measurement procedures nearly identical to those used in the BPA/EPRI study.

This paper compares the results obtained from those two outage cost surveys focusing on the differences in costs that was observed between them. The results of the comparison indicate that customer interruption costs have increased dramatically for residential customers. Comparison of interruption costs for commercial and industrial customers does not support the conclusion that interruption costs for these customers increased over the period.

The paper concludes with a discussion of the implications of these findings for utility planning and regulation

A practical approach for reliability evaluation of distribution networks

The authors describe a computer-aided method for the quantitative reliability evaluation of radial medium voltage networks. Reliability analysis is developed as part of a distribution network information and design system.

The outage rates, outage durations and costs of outages can be evaluated using the data included in the network database together with the reliability data for network components and the per unit values for the energy not supplied. Using the reliability calculation program together with the other design programs, optimal development plans for each network can be studied. In these studies both the technical restrictions and the total costs-including the costs of investments, losses and outages-must be included. Using the program, utilities have chosen the optimum types of network investments to improve the reliability of their medium voltage networks.

Practical experiences of these calculations at one utility are presented

Feeder-switch relocation for customer interruption cost minimization

Most electricity service interruptions are due to failures in the distribution network. In a competitive market, service quality and reliability have become an essential part of the business. In order to enhance the reliability in the distribution system, a value-based method is proposed in this paper to take load distribution changes into account and search for new locations of feeder sectionalizers such that the customer interruption costs (CIC) can be reduced.

Two stages are involved in the search. Using local information, the first stage determines the search direction and, in the second stage, it decides whether a crossover of the load point is beneficial. To avoid being trapped in a local minimum, a mutation technique is also applied to look for the global optimum.

Actual feeders were used in the tests and test results have shown that with a proper adjustment of the feeder sectionalizers, service reliability can be improved and the customer outage costs are reduced

Power interruption costs to industrial and commercial consumers of electricity

This paper summarizes the results of a survey of 210 large commercial and industrial customers to obtain detailed descriptions of the components of interruption costs they would experience under varying outage conditions.

In addition, the survey observed plant operating schedules, products and services, processes used, machinery used in production, backup generation and equipment designed to ensure power quality.

The paper describes a statistical approach for obtaining inexpensive outage cost estimates for individual customers by combining information from onsite interviews with less costly information obtained from utility representatives. Results from regression models estimated from the information obtained in the onsite survey are described in detail

Probabilistic assessment of power systems

Reliability is an important issue in power systems and historically has been assessed using deterministic criteria and indexes. However, these approaches can be, and in many cases have been, replaced by probabilistic methods that are able to respond to the actual stochastic factors that influence the reliability of the system.

In the days of global, completely integrated and/or nationalized electricity supply industries, the only significant objective was the reliability seen by actual end users. Also, the system was structured in a relatively simple way such that generation, transmission, and distribution could be assessed as a series of sequential hierarchical levels. Failures at any level could cause interruptions of supply to the end user.

All planning and operational criteria were intended to minimize such interruptions within economic limits. The system has been, or is being, restructured and now many individual parties are involved, often competitively, including generators, network owners, network operators, energy suppliers, regulators, as well as the end users. Each of these parties has a need to know the quality and performance of the system sector or subsector for which they are responsible. Therefore, there is now a need for a range of reliability measures; the actual measure(s) needed varying between the different system parties.

This paper addresses these issues and, in particular, reviews existing approaches and how these may be used and/or adapted to suit the needs and the required indexes of the new competitive industry and the different parties associated with it

Value-based reliability transmission planning

This paper presents a new value-based reliability planning (VBRP) process proposed for planning Duke Power Company's (DPC) regional transmission system. All transmission served customers are fed from DPC's regional transmission system which consists of a 44 kV predominately radial system and a 100 kV predominately nonradial system. In the past, any single contingency that could occur during system peak conditions and cause a thermal overload required the overloaded facility to be upgraded, regardless of the costs or the likelihood of the overload occurring.

The new VBRP process is based on transmission system reliability evaluation and includes the following important elements:

(1) a ten-year historical database describing the probabilities of forced outages for lines and transformers;

(2) a five-year average load duration curve describing the probability of an overload should a contingency occur;

(3) a customer outage cost data base;

(4) probabilistic techniques.

The new process attempts to balance the costs of improving service reliability with the benefits or value that these improvements bring to these customers. The objective is to provide customers with their required level of reliability while minimizing the total cost of their electric service.

Power distribution system planning with reliability modeling and optimization

A new approach for the systemized optimization of power distribution systems is presented in this paper. Distribution system reliability is modeled in the optimization objective function via outage costs and costs of switching devices, along with the nonlinear costs of investment, maintenance and energy losses of both the substations and the feeders.

The optimization model established is multi-stage, mixed-integer and nonlinear, which is solved by a network-flow programming algorithm. A multi-stage interlacing strategy and a nonlinearity iteration method are also designed. Supported by an extensive database, the planning software tool has been applied to optimize the power distribution system of a developing city

Value-based transmission planning and the effects of network models

A value-based automated transmission system planning model is presented in this paper and the impact of the various network representations on the results of the model is discussed. Value-based integrated resource planning provides a "societal cost" (utility operation and investment costs plus customer outage costs) minimizing composite generation-transmission system expansion plan.

The model trades-off and compares the costs and benefits of alternative generation and transmission resources using a consistent economic and engineering criterion in order to determine an "optimal" resource expansion plan. The generalized Benders decomposition algorithm with "importance sampling" used to solve the problem enables the model to estimate certain average information about scenarios or contingencies by examining only a very small fraction of all the scenarios or contingencies.

The impacts of system resources upon both real and reactive power can be analyzed when using the AC power flow equations. It is concluded that for transmission system planning where reactive power flows and voltage constraints are important, it is imperative that an AC power flow model be used. The combination of AC power flow and linearized power flow models, with linearization about the solution of the AC power flow model, was found to be a promising compromise between accuracy and computation time

Minimum cost analysis of station configurations

Substation configuration design in a power system involves both reliability and economic considerations.

This paper presents an optimum design selection methodology which minimizes capital costs, maintenance costs and outage costs. The minimization model proposed in this paper incorporates customer interruption costs due to substation originated failures and recognizes the different customer compositions at the various system load buses. Approximate equations and Markov models are utilized to calculate the substation originated failure event probabilities, frequencies and reliability worth, and a comparison is presented.

The effect of load model representation on the calculated reliability worth is also discussed

The use of probability techniques in value-based planning

Present techniques used in value-based planning do not properly represent either the durations of power system capacity outage nor the effects of outage on post-interruption demand.

Generation outage models do not relate the expected quantum of shortages to particular durations of outage. A model is proposed to compute this expectation by using the generator outage statistics in its entirety.

The application of this model to the IEEE test system gave different results, depending on which outage cost data were used. Consequently, there is a need for a uniform procedure to report outage costs. A “bottom-up” procedure based on end use is proposed as a possibility

Cost-benefit analysis of generation additions in system planning

Selection of the optimum generation reserve depends on both economic and reliability considerations. A new approach to select the optimum generator additions in a bulk power system by minimizing the total costs is presented in the paper. This includes investment, operational costs and unreliability costs in the form of outage costs.

The proposed approach uses the Dantzig-Wolfe decomposition approach to minimize the total costs

Evaluation of reliability worth and value of lost load

Customers' perceptions of reliability may not always reflect the level of reliability purported by traditional reliability indices. This has been recognized and efforts have been made by the electricity supply industry (ESI) in the United Kingdom to relate “reliability investment” with customers' marginal benefits obtained from such investment.

A difficulty encountered during such earlier and recent efforts has been the lack of appropriate valuation of these benefits. With a view to correcting this paucity, the authors have conducted studies, based on customer surveys, aimed at assessing the customer outage costs (COG) due to electric service interruptions.

The incremental values of these costs, ΔCOC, following reliability investment are considered proxies of reliability worth and customers' marginal benefits. The results of these studies have provided a very good insight into customers' concerns regarding supply interruptions, but most importantly a coherent method for evaluating the customer benefits (ΔCOC) has been developed and the required generic data for such evaluation generated.

Using these data, a consistent method for calculating the value of lost load (VOLL) is also developed

Probability distribution approach to describe customer costs due to electric supply interruptions

Considerable attention is being devoted to quantitative determination of electric power system reliability worth. A basic approach is to utilise customer interruption costs obtained from postal or in person surveys. The results obtained are transformed into customer damage functions which are applicable to individual customer classes and sectors. Standard customer damage functions utilise average customer costs for selected outage durations.

The paper presents a new approach which provides a three-dimensional representation of the probability distributions associated with customer outage costs. The results are utilised in a basic generating capacity adequacy assessment analysis to calculate an interrupted energy assessment rate, which provides an overall average cost per kilowatt-hour of unsupplied energy.

This cost value is considerably higher than the value obtained using a conventional customer damage function

Development of the ELDC and reliability evaluation of composite power system using Monte Carlo method

This paper presents a method for constructing composite power system effective load duration curves (CMELDC) at load points by a Monte Carte method.

The concept of effective load duration curves (ELDC) in power system planning is useful and important in both HLI and HLII. CMELDC can be obtained from convolution integral processing of the probability function of unsupplied power and the load duration curve at each load point. This concept is an analogy to the ELDC in HLI.

The reliability indices (LOLP, EDNS) for a composite power system are evaluated using CMELDC. Differences in reliability levels between HLI and HLII come from considering with the uncertainty associated with the outages of the transmission system. It is expected that the CMELDC can be applied usefully to areas such as reliability evaluation, probabilistic production cost simulation and analytical outage cost assessment, etc. in HLII. DC load flow and Monte Carlo methods are used in this study.

The characteristics and effectiveness of the methodology are illustrated by a case study of the IEEE RTS

Using partial discharge measurement technology to implement predictive maintenance in high voltage motor and generator stator windings

Partial discharge (PD) tests can determine which motor and generator stator windings are experiencing insulation problems. A deteriorated winding has a PD activity which can be 30 times or more higher than a winding in good condition. This great difference in PD activity enables even nonspecialized maintenance personnel to identify the few motors or generators in a company which need further investigation and/or maintenance.

After implementing on-line partial discharge tests companies can often confidently extend the outage between major machine inspections. This saves on outage costs and reduces the risk of a stator fault due to human error during maintenance.

Finally, on older machines, if there has been no increase in partial discharge activity over time, then the life of the stator winding can be confidently extended, saving a considerable capital expenditure. The PD tests discussed cost virtually nothing to perform, once the sensors are installed, since existing company staff can do the tests in about 30 minutes during normal motor or generator operation

Reliability worth evaluation for distribution system planning and operation using improved actual performance data

It is widely known that in reliability cost/worth analysis, customer outage cost should be taken into account for the delivery of energy services. Several methodologies have been proposed. However, these methods require a lot of long term statistical data e.g. failure and repair rates, which may not be available at present in developing countries.

There are some researches considering reliability cost/worth in term of Actual Performance data. Nevertheless, this method can only evaluate the past performance indices according to its past actual performance data. From this reason, it may not be possible to make a reasonable decision in distribution system planning and design.

This paper proposes an approach to cope with this problem. The past performance data and the targets of system planning, customer average interruption duration index (CAIDI) and average power not supplied (APNS), will be used to generate the expect interruption events. To handle the uncertainty in setting the system targets, fuzzy concept is then applied.

In this paper the proposed method together with Thailand's customer damage model (CCDF), obtained from the study conducted in the years 2000-2001, is employed to evaluate the reliability worth of the distribution system in Thailand.

Reliability is too important to leave it to the economists

When the electric power marketplace was regulated, its reliability was one of the most important aspects of its planning and operation. Reliability is looked at as an agreed upon goal of planning and operation. The problem is in defining just how reliable a power system is to be.

The reliability of a power system is not universally agreed upon, nor are the rules of operation to provide the reliability universally agreed upon. However, everyone understands that a more reliable supply of electricity results in a higher cost to electric customers. Unfortunately there is no level of reliable delivery that is generally accepted as the level that is "best" for every customer, and indeed, some customers will need more reliable delivery than others.

Further, there is no generally accepted model giving the tradeoff between electric energy reliability and the benefit electric energy brings to each customer. Last of all, it is not easy to differentiate between customers requiring more or less reliability when they are all connected to the same grid.

The author explores:

How reliable should a power system be?

How can the correct reliability be determined?

Would it help to differentiate different customer reliability needs and could these different needs be used to maintain high reliability standards while relaxing the restraints on the system?

How reliable would a typical power system be operated if it used a true cost benefit tradeoff between reliable operation and the actual costs of power outages to customers?

Should the level of reliability be set by congress or left to the marketplace?.

Transmission system reliability evaluation of KEPCO system in face of deregulation

The reliability evaluation of a transmission system is being realized to play an important role in the electric power systems under the situation of deregulation, because the electricity transmission system will be planned, operated and maintained by an independent transmission administrator in the new electric industry structure.

The new concept of the CMELDC (CoMposite power system Effective Load Duration Curves) has been developed to evaluate the nodal reliabilities, to simulate the nodal probabilistic production cost and to assess outage cost on the composite power systems by the authors in recently. Reliability of the transmission system can be also evaluated with the CMELDC.

The methodology of reliability evaluation of the transmission system is based on the concept that the reliability level of a transmission system is equal to the difference in the reliability levels of the composite power systems (HLII) and generation system(HLI).

In this study, the transmission system reliability of the KEPCO (Korea Electric Power Corporation) system was evaluated under a deregulated electricity market.

Failure contributors of MV electrical equipment and condition assessment program development

Implementation of condition assessment, or condition-based-maintenance involves many disciplines such as failure analysis, on-line diagnostics, diagnostic data interpretation, management and communication, follow-up corrective actions and lastly the program maintenance.

One of the difficult areas in the development of a comprehensive condition assessment program is the analysis of the probable contributing causes of failures, and selection of the appropriate on-line diagnostic tools to address the correct failure contributors. The specific failure contributors of the electrical power transmission and distribution equipment are documented in various sources, such as IEEE.

This paper illustrates the process of development of a comprehensive condition assessment program for medium voltage switchgear using the statistical data pertaining to the equipment failure contributing causes. Particular attention is given to the selection of specific on-line diagnostic techniques that are available today and that address the specific failure contributors.

Presented only briefly is the outage costs and RCM (reliability centered maintenance) concepts, related to a condition assessment program

Earthing of 130 kV power lines-effects on dependability and line cost

Power lines without overhead shield wires have low investment costs and their dependability in areas with low lightning incidence has been accepted. However, requirements for higher availability, improved power quality and lower maintenance costs may change the choice of line design as discussed in this paper.

Results are presented from a comparison of three different 130 kV power line designs, with and without shield wires, with respect to lightning performance, ground-return currents, dependability and costs.

The lightning performance is analyzed by EMTDC-simulations and the probability for line-to-line and line-to-ground faults are calculated. The severity of resulting voltage dips, and the corresponding outage cost for sensitive customers are discussed.

Fault current distributions for different grounding designs are calculated and required safety precautions and protective measures, on the power line or adjacent installations, are discussed. In conclusion: shielded lines have low outage costs, and show advantages in most technical aspects

Adequacy assessment and worth evaluation and its application to NUG planning in composite generation and transmission systems

A wide range of techniques have been proposed for adequacy evaluation in composite generation and transmission systems.

This paper utilizes a test system to illustrate and compare the adequacy indices obtained using an analytical approach and a Monte Carlo simulation method.

The paper presents the outage costs at the load buses and for the overall system using the cost of interruption data. The reliability worth implications of non-utility generation (NUG) injected into a composite generation and transmission system are illustrated by application to the test system

Intelligent configuration management of distribution network

This paper deals with the computerized configuration management of a distribution network.

A distribution management system (DMS) has been developed and integrated to other information systems. The DMS provides various functions for configuration management: topology supervision, restoration, maintenance outage planning and reconfiguration.

The field crew management and outage cost modeling sub-functions are utilized in the intelligent configuration management functions of the DMS

Reliability cost/reliability worth assessment of station configurations

Station configuration design is an important task in power system planning. Failure events originating in a station can result in multiple outages of generators, lines or loads. Failures of breakers, transformers and busbar sections are major causes of multiple outages.

This paper illustrates the effect of station originated failures on reliability and on the economic implications of reliability at different load buses in a composite generation and transmission system.

An optimum design selection methodology which minimizes capital costs, maintenance costs and outage costs is presented in this paper. The minimization model proposed in this paper incorporates customer interruption costs due to station originated failures and recognizes the different customer compositions at the various system load buses

Energy cost based technique for maintenance scheduling of generating systems

The two parameters of reliability and production cost are important in deciding the generating units' preventive maintenance scheduling. In this paper, a new approach for maintenance scheduling of generating units based on levelizing the energy cost has been developed.

The energy cost is divided into two parts. The first portion is the energy-production cost while the other is the outage cost (unreliability cost). The technique proposed has been applied to the IEEE Reliability Test System (IEEE-RTS).

The preventive maintenance schedule has been compared with other techniques (i.e. levelizing Energy Index of Reliability and levelizing Loss of Load Expectation). The effect of preventive maintenance on energy cost has been presented and discussed.

Value-based reliability evaluation of electric distribution systems

The authors describe the evaluation of the worth or value of distribution system reliability using quantitative reliability analysis and customer interruption costs. The ability to assess reliability worth makes it possible to optimize the reliability of a system by comparing the reliability worth with the associated system investment costs. The analyses include an evaluation of the reliability of different design/operating configurations of a distribution system and the corresponding reliability worths at the customer level.

The reliability of each system configuration is evaluated in terms of the system performance indices and the expected customer outage costs due to power interruptions

Understanding industrial losses resulting from electric service interruptions

A summary of research conducted to determine estimators of the perceived cost or losses to small industrial consumers attributable to electric service interruptions is presented. The effect on respondents with standby systems, categorized according to factors which contribute to the total industrial cost estimates and outage costs, are considered. It is shown that respondents having battery standby systems have estimated costs associated with plant/equipment damage, start up costs, and production losses much higher and total interruption costs lower than those that have an engine standby system or no standby system.

Analysis indicates that roughly 50% of the respondents cannot make up lost production for any of the interruption durations considered in the study

IEEE recommended practice for the design of reliable industrial and commercial power systems
Power Systems Reliability Subcommittee of the Power Systems Engineering Committee of the IEEE Industry Applications Society

The fundamentals of reliability analysis as it applies to the planning and design of industrial and commercial electric power distribution systems are presented. Included are basic concepts of reliability analysis by probability methods, fundamentals of power system reliability evaluation, economic evaluation of reliability, cost of power outage data, equipment reliability data and examples of reliability analysis.

Emergency and standby power, electrical preventive maintenance and evaluating and improving reliability of the existing plant are also addressed. The presentation is self-contained and should enable trade-off studies during the design of industrial and commercial power systems design, installation and maintenance practices for electrical power and the grounding (including both power-related and signal-related noise control) of sensitive electronic processing equipment used in commercial and industrial applications are presented.

Failure contributors of my electrical equipment and condition assessment program development

Implementation of condition assessment, or condition-based maintenance, involves many disciplines, such as failure analysis, online diagnostics, diagnostic data interpretation, management and communication, follow-up corrective actions and, lastly, the program maintenance.

One of the difficult areas in the development of a comprehensive condition assessment program is the analysis of the probable contributing causes of failures, and selection of the appropriate online diagnostic tools to address the correct failure contributors. The specific failure contributors of the electrical power transmission and distribution equipment are documented in various sources, such as IEEE.

This paper illustrates the process of development of a comprehensive condition assessment program for medium-voltage switchgear using the statistical data pertaining to the equipment failure contributing causes. Particular attention is given to the selection of specific online diagnostic techniques that are available today and that will address the specific failure contributors.

Presented only briefly are the outage costs and reliability-centered maintenance concepts, related to a condition assessment program.

Optimal switching device placement in radial distribution systems

This paper presents a new formulation for power system sectionalizing device placement taking into consideration outage, maintenance and investments costs.

The formulation of sectionalizing switches is a combinatorial constrained optimization problem with a nonlinear, non-differentiable objective function.

A solution methodology based on the optimization technique of simulated annealing, is proposed to determine:

(3) number of sectionalizing switches;

(4) locations of the switches.

The proposed solution methodology can offer a global optimal solution for the sectionalizing device placement problem which includes the reliability, investment and maintenance costs

Integrating transmission into IRP part II: case study results

This is Part II of a two paper set dealing with transmission and integrated resource planning.

Part I described an analytical approach to integrating transmission into the IRP framework and set forth the Comprehensive Electrical Systems planning Model (CESPLAN). The model, a mixed integer, nonlinear, stochastic programming formulation of the planning problem is solved using the generalized Benders decomposition algorithm with importance sampling to couple the contingency state space. The primary objective of this paper is to report a series of case studies performed with the model. Three sets of case study results are reported.

The first set illustrates that optimal resource plans created from the commonly used utility approach of two-step planning, i.e., first planning generation and demand-side resources and then determining the set of transmission resources that "best matches" the generation and demand-side plan, can lead to higher costs than when a more comprehensive, integrated planning approach is adopted.

A second set of case studies illustrates the use of "importance sampling", a procedure for reducing the number of sample configuration states of the system that must be simulated when estimating the effects of equipment outages on future system operating costs.

The third set of studies illustrate not only the optimal generation plan but also the optimal transmission plan is sensitive to planning uncertainties such as emissions allowance costs, customer outage costs, and future natural gas prices

A minimum cost assessment method for composite generation and transmission system expansion planning

Composite generation and transmission system expansion analysis should take into account both economic considerations and adequacy requirements. An optimum expansion plan should achieve the minimum total investment, operation and damage cost. A minimum cost assessment method for composite system expansion planning, which can be used to consider generation expansion and transmission expansion simultaneously, is presented.

The minimization model proposed to incorporate both operating and outage costs can recognize different customer damage functions at different load buses and includes the duration of the simulated contingency system states . A computer program based on the presented method has been developed to provide a set of line, load bus, generator bus and system indices which can be used to select optimal expansion plans at different load growth levels.

Case studies in which the method is applied to the IEEE Modified Reliability Test System indicate its effectiveness

The economic aspect of reliability in distribution system planning

A distribution system planning procedure to handle reliability not only as an important type of analysis but as an integrated part of the cost minimization problem is described. The reliability is described as an operating cost by evaluating the cost of non-delivered power (NDP) and non-delivered energy (NDE). Reported case studies show that the economic assessment of reliability is of great importance in distribution system automation and design.

The case studies show that the cost of outages tends to dominate the total costs even when the specific costs of outages (NDP/NDE) are quite low. Distribution planning studies also reveal that uncertain outage cost premises may be investigated and compensated by sensitivity analyses, helping the planner to achieve a safer design strategy. In case of costs of outages, the planning approach described makes it possible to establish a level of distribution system reliability that balances private and socio-economic cost/benefit criteria

Customer cost of electric service interruptions

An approach often used to estimate power-system reliability worth is to determine consumers' monetary losses resulting from service interruptions, i.e. the cost of unreliability.

Previously, studies have been conducted to provide estimates of customer interruption costs, and a wide range of methodologies has evolved. There is no universal agreement on the appropriateness of methodologies to particular situations nor on the interpretation of the results obtained, but some appear to be more acceptable and useful to the industry than others.

A survey is presented of the techniques available for estimating customer interruption costs, the rationale of those that are currently popular is discussed, and the application of such cost data in creating a composite customer damage function is explored

Distribution system planning with evolutionary programming and a reliability cost model

Cost of reliability of optimal distribution system planning is considered. The reliability cost model has been derived as a linear function of line flows for evaluating the outages. The objective is to minimize the total cost including the outage cost, feeder resistive loss, and fixed investment cost.

Evolutionary programming was used to solve the very complicated mixed-integer, highly nonlinear and non-differential problem.

A real distribution network was modeled as the sample system for tests. There is also a higher opportunity to obtain the global optimum during the EP process

Reducing the cost of energy delivery disruptions: the role of advanced technology

In July and August 1996, the electric grid in the Western United States experienced widespread power outages from Southern California to Western Canada. These large disruptions provided a reminder of the vulnerability of energy delivery systems. While these disruptions may have been isolated events, there are a growing number of threats to the security, stability, reliability and safety of national energy delivery systems.

For a fraction of the billions of dollars a year these outages cost the economy, technologies could be developed that would reduce the threats and consequences of such disturbances. Many of these same developments also would better enable energy delivery systems to accommodate the demands of pending competition in the energy marketplace

Value-based distribution system reliability analysis

This paper presents an integrated scheme for value-based distribution system reliability analysis. The approach balances between the cost of improving service reliability for customers and the economic benefits of such improvements. A set of reliability indices, such as: load/energy curtailed, the cost of outages, and the cost of interruption to a customer based on the component outage data is calculated. The scheme utilizes the Distribution and Industrial Systems Reliability Evaluation Program (DISREL) for power distribution system reliability assessment and value-based distribution system resource analysis. The proposed scheme is tested on a simple distribution system and 32-bus distribution system

Power interruption costs to industrial and commercial consumers of electricity

This paper summarizes the results of a survey of 210 large commercial and industrial customers to obtain detailed descriptions of the components of interruption costs they would experience under varying outage conditions. In addition, the survey observed plant operating schedules, products and services, processes used machinery used in production, backup generation and equipment designed to ensure power quality.

The paper describes a statistical approach for obtaining inexpensive outage cost estimates for individual customers by combining information from on-site interviews with less costly information obtained from utility representatives. Results from regression models estimated from the information obtained in the on-site survey are described in detail

Lifting structures to increase groundline clearances

Deregulation within the electric utility industry is forcing many companies to stretch the capacities of their mature transmission lines. No longer are companies in control of new generation locations or capacities. Their mission has changed from supplying electricity to regional customer to that of the movement of power over their grid. Once the RTOs (regional transmission operators) are in place, there will be even more pressure to maximize the thermal capacity of existing transmission lines.

The actual cost of line outages for maintenance of rebuild work will make many present day work procedures obsolete. Thus, the industry is changing to methods of safely increasing the existing structure heights without removing the line from service.

Using utility information to calibrate customer demand management behavior models

Summary form only given as follows. In times of stress customers can help a utility by means of voluntary demand management programs if they are offered the right incentives. The incentives offered can be optimized if the utility can estimate the outage or substitution costs of its customers.

This paper illustrates how existing utility data can be used to predict customer demand management behavior. More specifically, it shows how estimated customer cost functions can be calibrated to help in designing efficient demand management contracts.

A discrete-event simulator for predicting outage time and costs as a function of maintenance resources

With the increasing air traffic and growth of deployed FAA equipment, high equipment availability and low outage time is also becoming more important. While the use of simulation models and simple queuing models for assessing the impact of staffing on availability has been available for more than 5 decades, it has not been widely used because of the cost and complexity of implementation.

This paper presents an analytical model and software tool that can be used by non-experts to relate FAA maintenance resources including staffing, training, shift allocation, and geographical deployment to National Airspace System (NAS) facility and service downtime and availability.

The analytical methodology and tool presented in this paper make it possible for any user to rapidly assess how changes in staffing, training. equipment count, and reliability will impact outage time, availability, maintenance backlog and technician utilization. It allows users to easily perform parametric studies on a variety of "what if" scenarios related to economics and capacity.

The most significant benefit is that these results can now be made available to analysts and decision makers. The net result will be more informed decisions to account for the impact of maintenance resources on NAS capacity and overall economics

The sort of fault diagnosis in large synchronous generators by analytic hierarchy process (AHP) method

Generators are the most important and valuable equipment in power systems. Internal faults not only damage the generator but also interrupt electricity generation and cause load rejection. If they are not detected immediately they spread, then repair becomes very long and tedious and the availability of the generator is lost.

Unplanned repair costs of different parts of a generator and pertinent cost of generator outage during its effective life time is much more than the cost of detector equipment. Fault diagnosis in a generator is done by many methods some of which are on-line and others are off-line. Using the different equipments for fault diagnosis in a generator may be ideal at first glance, but because of equipment cost, unavailable technology, repair, maintenance and so on is not ideal (according to many power plants in Iran). Then the device which detects the most probable faults in order to reduce fault occurrence is very important.

According to the above, information about fault occurrence in generators over ten years (1986-1996) are gathered by questionnaire. Then, the most probable fault in generators is made known by the AHP method

Comparison of fault management applications in French and Finnish distribution control centers

This paper compares two systems providing advanced functions for real-time management of power distribution networks developed in Finland and in France. The overall aim of these systems is to minimize the operational costs (e.g. power losses, outage costs) subject to the technical constraints (e.g. voltage level, thermal limits).

These are to be integrated with a supervision control acquisition system (SCADA) and heterogeneous databases such as network and geographical information systems (AM/FM/GIS). In this paper, the authors briefly introduce both systems and discuss their similarities and differences in more detail.

The main focus is on the systems' connection to SCADA and fault management functions but both systems provide other functionalities beyond the scope of the present paper

Reliability indices estimation of unstationary distribution networks

The paper presents an efficient and overall analytical approach towards the prognosis of reliability indices in the process of development of medium voltage city distribution networks.

The presented model gives possibility for estimation of duration of the interruption of supply of the load points in question, due to unexpected failure at some, arbitrarily chosen, element of radial distributive network. Repair crew movement during searching for the faulted cable section is modeled, in order to estimate time needed for isolation and renewal of supply of load points.

The differences in strategies of searching and isolating of the faulted section are also taken into consideration. The reliability analysis is possible in the case that the dispatcher and the crew for maintenance search for the section by use of halving method or by the method of measuring the resistance of isolation using megaommeter.

Application of the model and developed computer program is illustrated on the example of the real network of the city of Novi Sad. Some feeders are analyzed as unstationary elements which during the planned period change the configuration, number of load points, load and unit outage costs. The change of configuration is manifested by connection of new MV/LV substations between the existing ones, or by prolongation of lines. The change of the configuration of open loop depending on link arrangement is considered.

The results give a real reliability picture of the present but also of the future MV network. In addition, data thus obtained can be used as basic ones for the estimation of benefits in cost-benefit analyses