2012 State of the Interconnection

Western Electricity Coordinating Council

By

WECC Staff

July 2013

Table of Contents

Table of Figures

Table of Tables

Executive Summary

The objective of the State of the Interconnection report is to provide Western Electricity Coordinating Council (WECC) members and stakeholders with an independent assessment of the data collected annually in the Western Interconnection. In addition, this 2012 report builds on that objective with the goal of developing reasonable measurements that will identify reliability trends in the Western Interconnection. This report includes historical data; however, the focus of the evaluation is primarily on the 2011 and 2012 calendar years.

Major Areas of Focus

Load Growth: The average load growth in the Western Interconnection prior to the 2008 U.S. economic recession was 1.3 percent annually. In 2011 and 2012, the annual load growth increased Interconnection-wide to 1.8 percent with an annual energy load in 2012 of approximately 885,000 GWh. The Northwest U.S. subregion remains the largest load area, while the Northern California Baja, Mexico subregion continues to lead in overall load growth.

Unplanned Generation Outages: The Western Interconnection has experienced an increase in the total number of unplanned generation outages in recent years; however the overall frequency of events per unit has declined or remained stable across the fleet.

Resource Capacity: Wind-fueled resources continue to experience the largest annual capacity increase with a 28 percent growth, 4.3 GWh, in 2012.

Transmission Expansion: In 2012, transmission expansion was relatively small compared to recent years with about 600 miles of new transmission lines added to the system.

Unplanned Transmission Outages: The number of unplanned transmission outages continues to remain consistent annually. Thirty five percent of the outages are weather related, but the duration of these outages is relatively short at less than a minute, indicating the system is operating as designed.

Load Loss Events: There were three significant reported load loss events in 2012, but the overall load lost due to these events was relatively small compared to events in 2010 and 2011. Equipment Failure continues to be the largest category of reported events and the overall severity of these events has been increasing in recent years.

Misoperation of Protection Systems: Incorrect setting/logic/design errors continue to drive the misoperation of protection systems. Failure to Trip[1] and Slow Trip[2] are a very small portion of the events, with almost all of the misoperations categorized as either an Unnecessary Trip During a Fault[3] or Unnecessary Trip Other Than Fault.[4]

[1] Failure to Trip - Any failure of a Protection System element to operate when a fault or abnormal condition occurs within a zone of protection

[2] Slow Trip - Any failure of a Protection System element that is slower than planned to operate when a fault or abnormal condition occurs within the zone of protection

[3] Unnecessary Trip During a Fault - Any unnecessary Protection System operation for a fault not within the zone of protection

Reliability Coordinator (RC): The RC function has acquired two new tools, NetSens and the Real Time Line Outage Distribution Factors (RTLODF) application, both will significantly aid in determining the most effective mitigation actions.

Reliability Standard Violations: In 2011 and 2012, the number of public and non-public reviewed and validated Reliability Standard violations in both the Operation & Planning (O&P) and Critical Infrastructure Protection (CIP) categories has stabilized. Almost all of the violations were self-reported or self-certified by the entities. The largest violation categories remain Protection and Control (PRC), followed by Voltage and Reactive (VAR), and then Modeling Data and Analysis (MOD). The largest number of CIP violations continues to be centered on the protection of Critical Cyber Assets.

2012 Recommendations

The 2011 and 2012 State of the Interconnection reports have laid the framework to conduct future analyses that are necessary to identify reliability trends. The objective of analyzing the trends is to identify proactive measures that can be taken to prevent outages. Therefore, each report has provided recommendations, listed below, on where additional analyses are necessary. Future reports will incorporate the additional analyses, as they are performed, and provide status updates on past recommendations.

Summary of the 2011 ongoing recommendations:

- Perform analyses on how transmission element physical attributes (e.g., structure type, insulator type) influence line performance.
- Establish an event severity index concept.
- Perform an analysis of Reliability Standards violation trends for individual requirements and drill down more deeply into the individual violation information to determine whether there are lessons or recommendations for outreach, education and training on requirements that may be most problematic. The additional analysis may also inform and prioritize compliance input into improved standard development efforts.

Summary of 2012 analyses recommendations:

- Investigate the decline of load in the Rocky Mountain subregion.
- Investigate removing the impact of temperature variance on load data.
- Monitor coal-fueled resources to determine if the decrease in generator outages is a new trend or if 2012 was just a better operating year than previous years.
- Explore why some types of resources experience longer outage durations than others.
- Perform additional analyses of generation outages to determine if the time of year, day or even day of the week of an outage is influencing the duration of the outage.

[4] Unnecessary Trip Other Than Fault - Any unnecessary Protection System operation when no fault or other abnormal condition has occurred

- Conduct a study of subregional areas to ascertain where weather-related transmission outages are more likely to occur and provide valuable insight related to avoiding longer duration outages.
- Acquire more meaningful results from analyses of the frequency of outages per transmission line size (voltage and distance).
- Study the WECC Event Analysis Cause Categories to determine which categories and subcategories, if any, have a higher percentage of load loss associated with them.
- Establish an appropriate loss of load threshold to allow for the measurement of a reasonable level of reliability.
- Normalize reported event analysis events by how much total load was demanded by the system at the same time of the outage or event.
- Conduct a correlations study between Cause of Misoperations, Misoperation Categories and Misoperation Technologies and their impact on risk to reliability.
- Determine if studying System Operating Limits (SOL), Interconnected Reliability Operating Limit (IROL) exceedances and Facility Path Ratings could provide insights to reliability trends for the Western Interconnection.
- Correlate the Reliability Standards violation data with actual outage and event analysis data.

Introduction

The mission of the Western Electricity Coordinating Council (WECC) is to promote and foster a reliable and efficient Bulk Electric System.

WECC is the Regional Entity responsible for coordinating and promoting Bulk Electric System reliability in the Western Interconnection. In addition, WECC provides an environment for coordinating the operating and planning activities of its members as set forth in the WECC Bylaws.

In 2012, WECC produced the first State of the Interconnection report.[5] The report was created in response to an initiative to study vulnerabilities in the Western Interconnection begun by WECC's Reliability Policy Issues Committee. The objective of the report is to provide WECC's members and stakeholders with an independent assessment of the data collected annually in the Western Interconnection. This current report builds on that objective with the goal of developing reasonable measurements that will identify reliability trends in the Western Interconnection. With increased examination and analysis of the data in future years, WECC expects to determine trends that indicate risks to reliability and, where possible, provide recommendations for addressing the identified risks.

Measures of Reliability

What is reliability, and how is it measured? In terms of the electric grid, reliability is the ability of the system to perform its required function under stated conditions for a specific period of time. This means the system should satisfy demand through the production and delivery of electricity. When there is a loss of either production or delivery, there is an increased risk to the system being reliable. If this loss leads to the system not meeting its demand, then the system was unreliable during that time. There is seldom a single 'proper' statistical technique to analyze any particular situation. Statistical analysis is a way of thinking about data that carefully identifies assumptions and precisely asks questions. To measure how reliable the Western Interconnection is each year, three factors are assessed. First, the frequency of events: how often events occur and the reasons for them. Second, the duration of each event: how long it takes for the system to return to performing its function. Last, the severity of the events: how much demand is not met (i.e., how many customers were without power).

State of the Interconnection Narrative

This report illustrates key aspects to the measurement of reliability by first laying the groundwork for how immense and complex the Western Interconnection is geographically, and how this leads to a diverse need for electricity. The report then discusses what resources are being used to produce electricity to meet the demand and what resources were added the previous year to continue to meet the growing demand (Demand section). The report then delves into the frequency and duration of events that cause the loss of generating resources, followed by a discussion of the delivery system, the miles of integrated transmission lines used to move electricity and the miles added each year to meet the growing demand. The frequency and duration of events that led

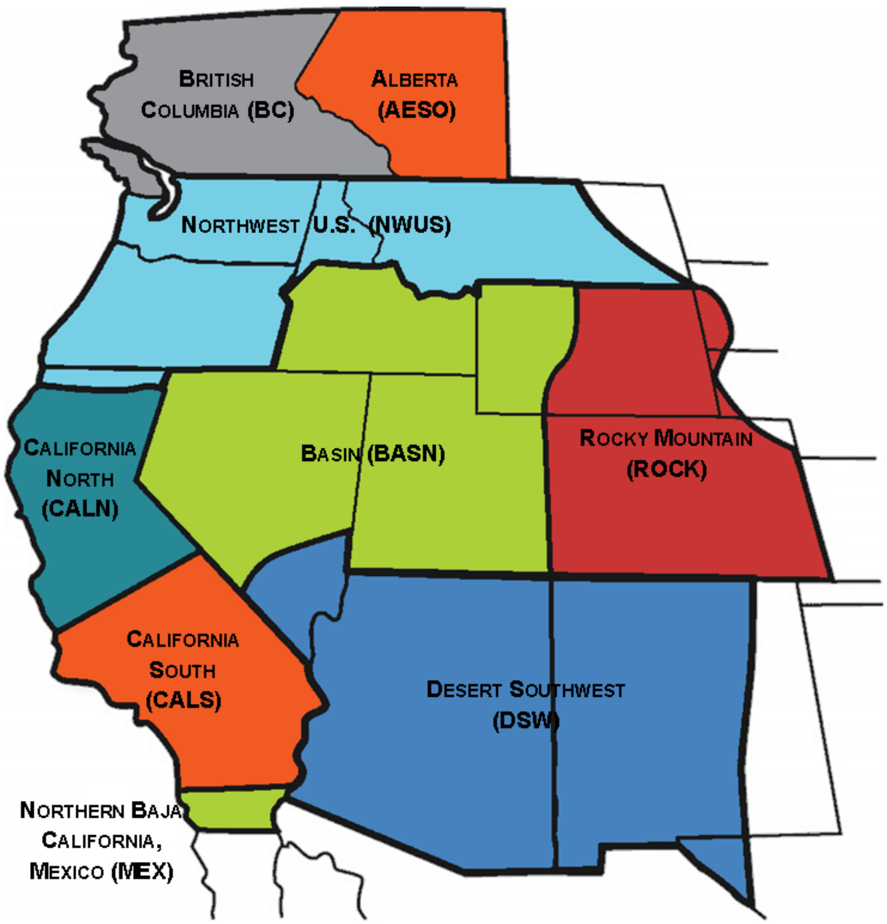
---

[5] State of the Interconnection Report: http://www.wecc.biz/Planning/PerformanceAnalysis/Documents/2011_WECC_SOTI_Report.pdf

to the loss of the transmission lines are also analyzed (Generation and Transmission System sections). It is important to note that not all of the generation or transmission outages led to demand not being met. Thus, the report also explores the subset of events that led to demand not being met (Event Analysis section). The last three sections discuss technology, as well as monitoring practices in place to not only prevent future events but to mitigate the impacts of those events.

Western Interconnection – By the Numbers

The Western Interconnection is the largest geographical North American Regional Entity at about 1.8 million square miles, with a population of 81.6 million people. [6] There are nine WECC subregions: Alberta, Basin, British Columbia, California North, California South, Desert Southwest, Northern Baja California Mexico, Northwest U.S. and Rocky Mountain. A subregion is a reporting area in the Western Interconnection that is determined by major transmission paths and facility ownership. These subregions group, divide or wholly include the states and provinces that make up the Western Interconnection.



[6] Population estimate calculated by collecting census data from: http://quickfacts.census.gov/qfd/index.html; http://www.bcstats.gov.bc.ca/StatisticsBySubject/Demography/PopulationEstimates.aspx; http://municipalaffairs.gov.ab.ca/mc_official_populations.cfm; and http://www3.inegi.org.mx/sistemas/mexicocifras/default.aspx?e=2

A diverse mix of fuels is used to generate electricity in the Western Interconnection: coal, gas, nuclear, hydro, geothermal, wind, biomass, solar and other conventional fuel resources. The 2013 summer expected maximum capacity for these fuels is 233,083 MW for the entire Western Interconnection. The breakdown of this generation capacity (MW) by WECC subregion and generation type is presented in Table 1.

Table 1: Summer Expected Maximum Capacity (MW) as of 12/31/2012 by Subregion[7]

Summer Expected Maximum Capacity (MW) as of 12/31/2012 by Subregion										
	AESO	BASN	BC	CALN	CALS	DSW	MEX	NWUS	ROCK	WECC Total
Coal	5,654	5,438	-	129	1,940	11,271	-	6,530	7,837	38,798
Gas	5,550	4,149	1,295	17,869	23,939	21,223	1,943	8,043	6,870	90,879
Nuclear	-	-	-	2,240	2,246	3,937	-	1,130	-	9,553
Hydro	911	2,379	12,676	6,864	1,555	3,954	-	31,851	1,381	61,570
Geothermal	-	412	-	841	773	-	570	-	-	2,597
Wind	1,097	2,460	403	2,261	3,567	724	10	6,846	2,384	19,753
Biomass	280	47	344	470	391	48	-	633	4	2,217
Solar	-	21	-	503	956	520	5	30	90	2,124
Other Conv.	-	73	15	2,492	1,761	328	89	214	620	5,592
Total	13,491	14,980	14,733	33,670	37,127	42,003	2,617	55,275	19,186	233,083

Table 2 represents the non-coincident summer and winter peak demand for the WECC subregions. The prior year's coincident summer and winter peak demand for the total WECC region were 150,913 MW and 124,369 MW, respectively. It is noteworthy that some parts of the Western Interconnection are summer peaking, while others are winter peaking[8].

Table 2: Actual Peak Demand (MW) by Subregion

Actual Peak Demand (MW) by Subregion										
	AESO	BASN	BC	CALN	CALS	DSW	MEX	NWUS	ROCK	WECC coincident
2012 Summer	9,885	13,809	7,774	25,201	34,008	28,426	2,302	24,616	11,666	150,913
2011-12 Winter	10,599	10,744	9,840	17,820	22,242	16,284	1,466	27,298	10,016	124,369

Table 3 and Table 4 present the existing transmission line circuit miles, by voltage level. There are a total of 127,993 linear miles of transmission circuits above 100 kV. This amounts to 8.28 feet of transmission circuit miles for every person living in the Western Interconnection.

---

[7] Nameplate capacity is reported for wind and solar resources. All other resources are reported as summer expected capacity.

[8] Basin, California North, California South, Desert Southwest, Northern Baja California Mexico, and Rocky Mountain subregions are summer peaking while Alberta, British Columbia, and the Northwest U.S. subregions are winter peaking

Table 3: Transmission Line Circuit Miles – AC Voltage (kV)

Transmission Line Circuit Miles - AC Voltage (kV)							
AC Voltage	100-120	121-150	151-199	200-299	300-399	400-599	Total AC Miles 126,249
Line Miles	30,269	16,870	3,549	43,769	10,770	21,022	

Table 4: Transmission Line Circuit Miles – ± DC Voltage (kV)

Transmission Line Circuit Miles - ± DC Voltage (kV)					
DC Voltage	200-299	300-399	400-599	600+	Total DC Miles 1,744
Line Miles	147	-	1,333	264	

Demand

Each year, WECC requests from all Balancing Authorities in the Western Interconnection an overview of projected electricity demand growth, as well as generation and transmission additions. This data is used for a variety of analytic activities and reporting purposes.

As previously mentioned, the definition of reliability is the ability of the system to perform its required functions. In terms of the Western Interconnection, this means the system's ability to deliver electricity to those who have a demand for it, otherwise referred to as the load on the system. The data collected from Balancing Authorities has been used in this section to evaluate the demand of the Western Interconnection.

Observations

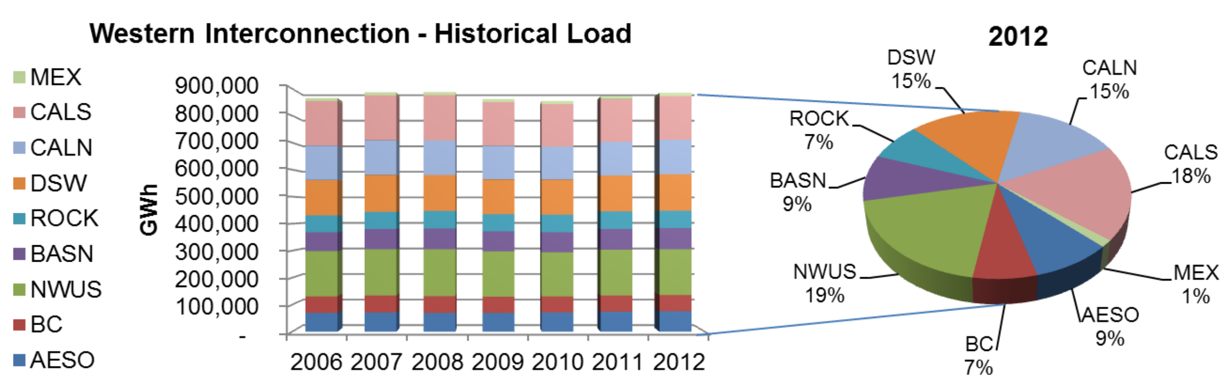
There are two important factors of the load that need to be analyzed, the annual energy load and the seasonal peak demand. The 'peak' demand hours of the summer and winter seasons are the major drivers to how much new generation and transmission is needed to keep the system reliable.

<u>Annual Energy Load</u>

When analyzing the first key component, annual energy load, the 2012 data shows the Western Interconnection experienced its second consecutive year of increased annual load, an overall increase of roughly 1.4 percent or 12,000 GWh.

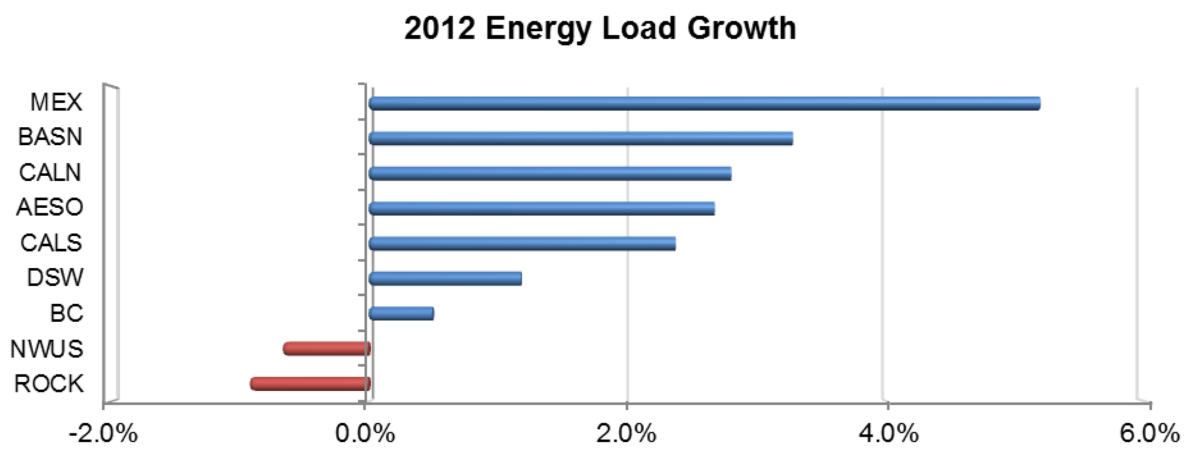
Figure 1 illustrates that the overall energy load for 2012 was roughly 885,000 GWh, with 33 percent of this load contained in the two California subregions, an additional 19 percent in the Northwest U.S. subregion and 15 percent in the Desert Southwest subregion.

Figure 1: Western Interconnection – Historical Load



The Northwest U.S. subregion continues to remain the largest load subregion in the Western Interconnection. However, this subregion experienced a decrease in annual energy load of approximately 0.7 percent in 2012 as illustrated in Figure 2.

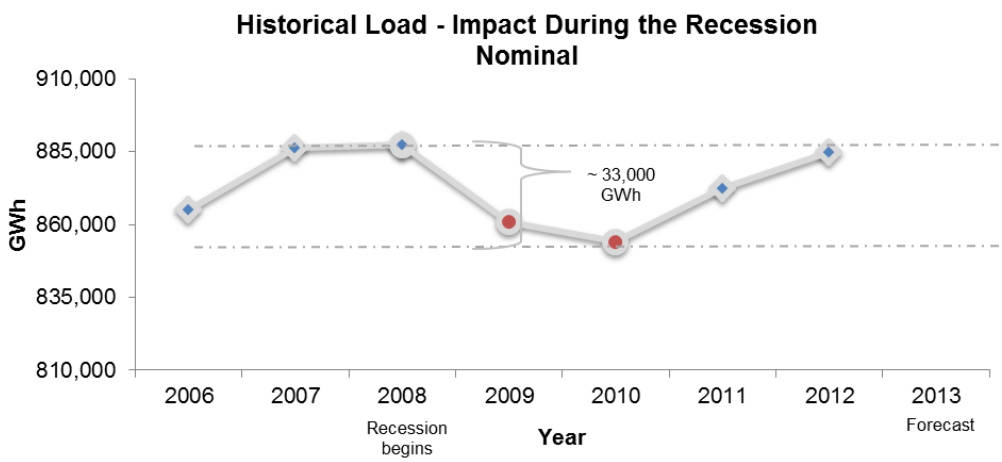
Figure 2: 2012 Energy Load Growth



California South, the second largest load subregion, experienced a 2.4 percent load growth in 2012. If the trends continues this subregion may become the largest load subregion by 2014. Northern Baja California, Mexico continues to be the smallest load subregion; however this subregion experienced a significant 5 percent load growth in 2012 following a 7.4 percent growth rate in 2011. Alberta continued its two-year average growth rate of 2.7 percent and remains the only subregion to not have experienced a negative growth rate during the recent economic recession.

During the recent 2008 U.S. economic recession the annual total load experienced a reduction of approximately 33,000 GWh, or 3.7 percent.[9] This reduction is from a high of approximately 887,000 GWh in 2008 to a low of roughly 854,000 GWh in 2010. As illustrated in Figure 3, the Western Interconnection has recovered almost all of the reduction in annual energy load.

Figure 3: Historical Load – Impact During the Recession, Nominal

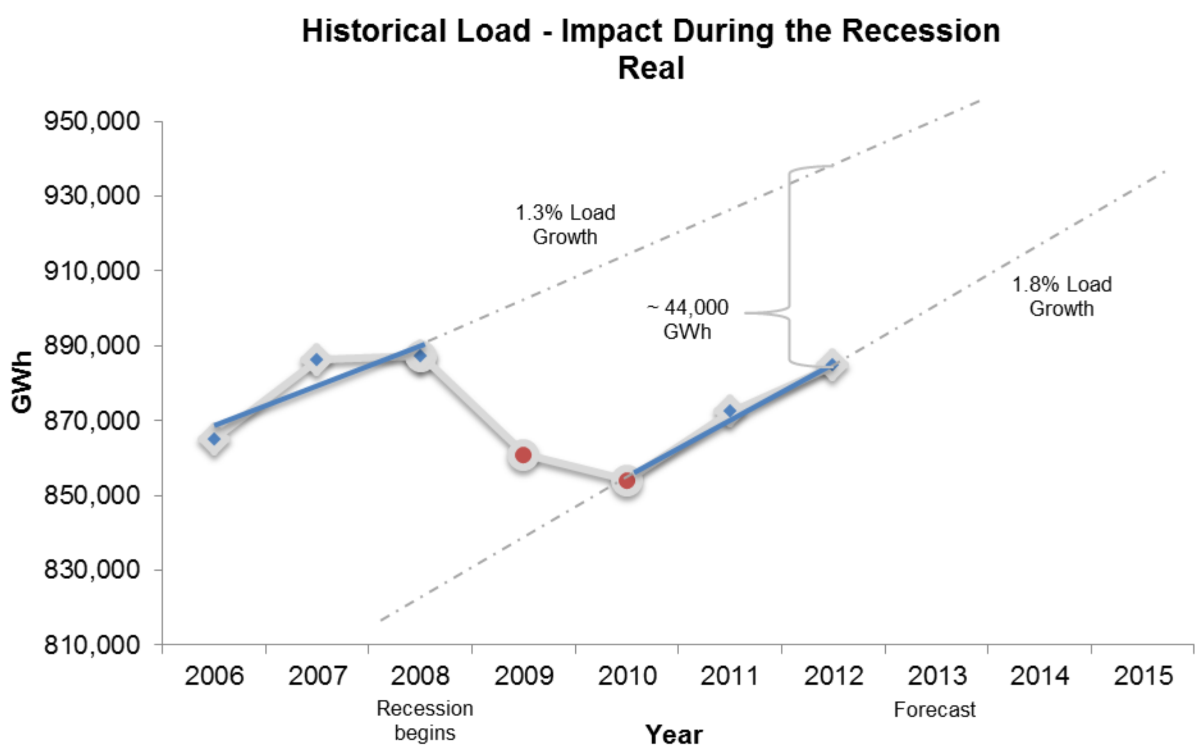


[9] http://www.hsgac.senate.gov//imo/media/doc/Financial_Crisis/FinancialCrisisReport.pdf?attempt=2

The subregions of British Columbia, Alberta and Northwest U.S. have recovered roughly 11,000 GWh since 2010. California North and California South have recovered approximately 10,000 GWh and the Desert Southwest and Basin subregions an additional 9,000 GWh. Northern Baja California, Mexico has recovered just over 1,000 GWh. Further analysis is needed to understand why the annual load in the Rocky Mountain subregion experienced a reduction in 2012.

Although the impact, Interconnection-wide, was a 3.7 percent loss of annual energy load, the true impact during the recession, referred to as the real impact, was approximately 44,000 GWh, or 5 percent. As illustrated in Figure 4, in order to measure the real impact, the annual growth rate before the recession is factored into the difference.

Figure 4: Historical Load – Impact During the Recession, Real



The Western Interconnection averaged a 1.3 percent annual load growth over the two years before the recession, (2006 and 2007). The data illustrates the annual load growth since the recession has rebounded to a 1.8 percent annual growth rate. Had the Western Interconnection continued to grow at pre-recession levels, the load in 2012 would have been around 44,000 GWh higher or close to 930,000 GWh. This load loss is equivalent to five to seven years of load growth.

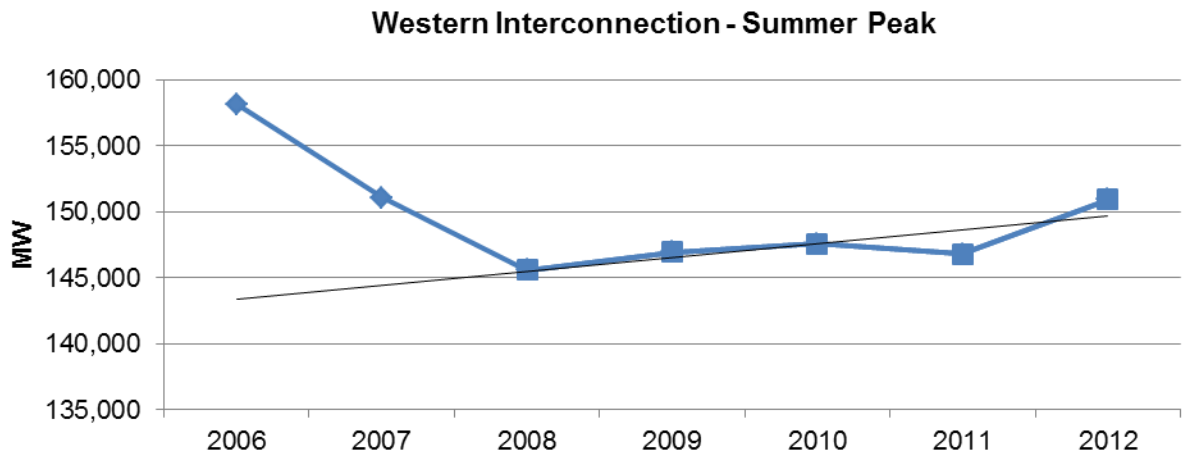
Seasonal Peak

When analyzing the second key factor of load, seasonal peak demand, the data reveals that although the annual energy load has begun to increase each year, without factoring in the change in temperature variances, the seasonal peak demands have grown at a lower rate than the annual energy growth rate.

Reduction of the peak demand is beneficial in two ways. First, risk to reliability is reduced because the strain placed on the Western Interconnection to supply large amounts of load is decreased and second, reducing the overall difference from the peak demand to the base load demand helps in resource planning and could requires less future resources.

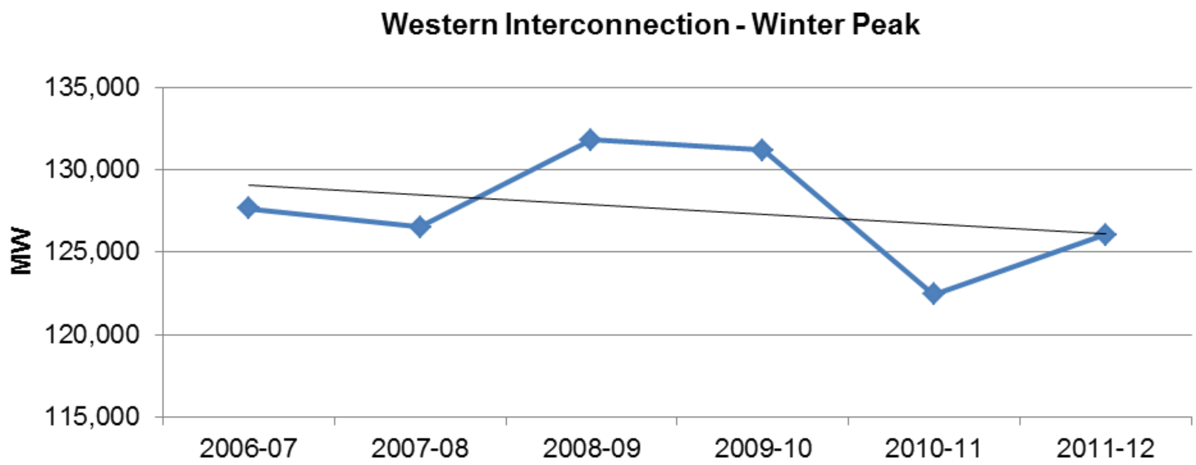
As illustrated in Figure 5, the summer peak (June through September) was slightly higher in 2012 than 2011, but the overall trend was continued from 2008.

Figure 5: Western Interconnection – Summer Peak



The Western Interconnection's all-time highest peak occurred in 2006 and was driven by an Interconnection-wide heat spell. As for the winter peak, (December through February), Figure 6 reveals the trend is downward sloping. Much of this downward trend can be contributed to recent mild winters.

Figure 6: Western Interconnection – Winter Peak



Further analysis is needed to normalize the data and remove the impact due to temperature variances in order to focus on the overall efforts of the conservation programs in the electric industry. Additionally, subregional peaks will be analyzed separately since some of the subregions tend to be summer peaking and others winter peaking.

Summary and Recommendations

Although the recent recession had an impact on the overall load required of the system, the load in most of the subregions in the Western Interconnection has begun to recover.

The last two years of historical energy load reveal the Western Interconnection has regained an annual 1.8 percent load growth, which exceeds the growth rate prior to the recession. The Northern Baja California, Mexico subregion continues to lead in overall growth, while further analysis is needed to understand the recent decline of load in the Rocky Mountain subregion. Even with the overall load increasing each year, the load demanded on the peak hour of the seasons continues to grow at a slower rate, which leads to less variables and a decrease to the risk to reliability due to a loss of load event.

Generation System Availability

The Generating Availability Data System (GADS)[10] is a North American Electric Reliability Corporation (NERC) database used to collect the annual submittal of historical operation characteristics for generation resources. This data is used in analyzing historical trends of planned and unplanned outages, as well as unit de-rates where a resource does not operate at full capacity.

GADS has been a tool used by the industry to analyze generation information for more than 30 years; however, contribution of data has not always been mandatory. In 2012, the NERC Board of Trustees approved mandatory GADS reporting for conventional generating units. Currently, 50 MW and larger conventional units have been included, and units 20 MW and larger were phased in beginning January 1, 2013.

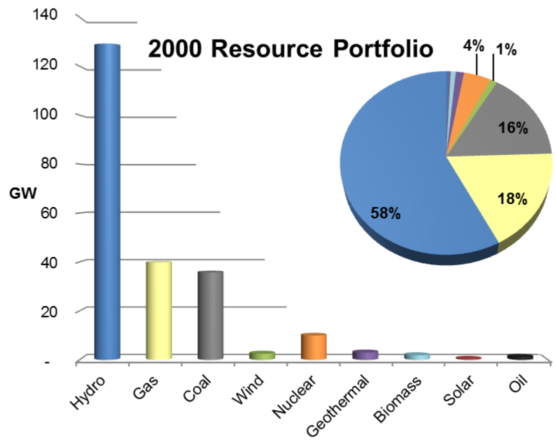
There was a noticeable decrease in 2011 reporting due to the effort in transitioning to the new process. However, with the implementation of mandatory reporting, there was a large increase in 2012 reporting. Even with the abnormalities, the data provided from GADS can be used to report on the historical and current frequency and duration of generation events as a measure of risk to reliability in the Western Interconnection.

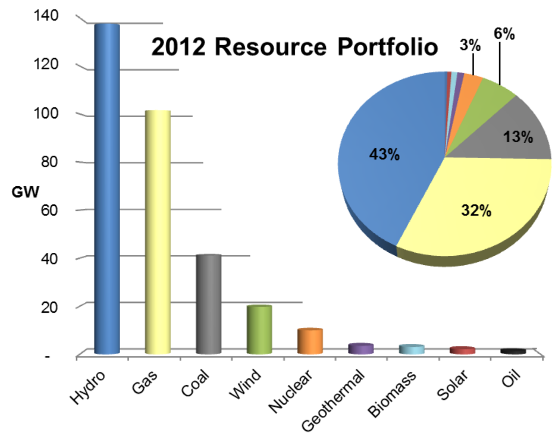
Generation Resource Portfolio

Figure 7 represents the fuel type distribution of the generation portfolio of the Western Interconnection for 2012 compared to 2000.

[10] Generating Availability Data System (GADS): http://www.nerc.com/pa/RAPA/gads/Pages/default.aspx

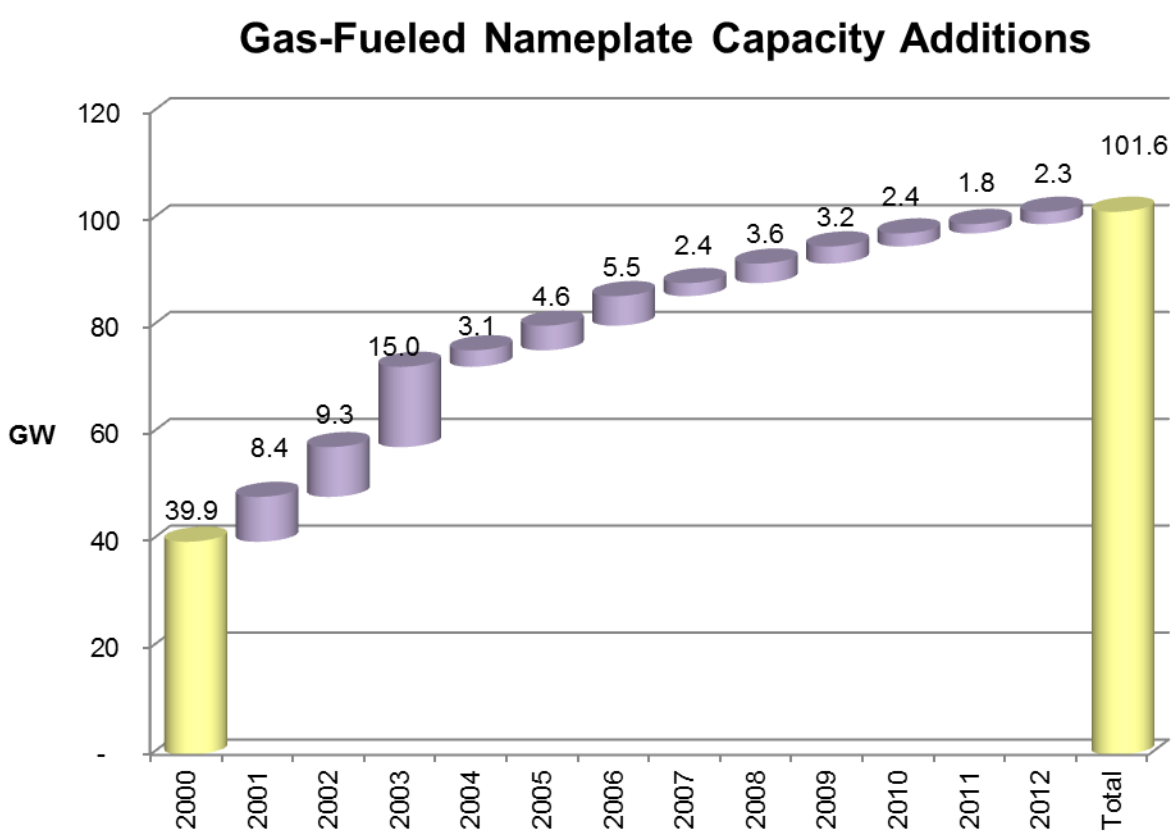
Figure 7: Resource Portfolio: 2000 and 2012[11]





When viewing the two portfolios, it is clear that although hydro-fueled resources continue to be the largest, the percentage has declined significantly from 2000 to 2012. While the majority of this decrease is due to the rapid increase of gas-fueled resource capacity, the Western Interconnection has also encountered an influx of wind-fueled resources to the portfolio.

Figure 8: Gas-Fueled Nameplate Capacity Additions: 2000 to 2012



[11] The Generation Resource Portfolio is calculated using data collected for the NERC Long Term Reliability Assessment and includes all reported units of the Western Interconnection.

Figure 8 illustrates the annual growth of the gas fueled resources since 2000. The data reveals that the majority of gas capacity increase occurred during the early 2000s in reaction to the Western Energy Crisis.[12] There are two motives that supported the growth: 1) as electricity prices increased, the gas-fueled resources were becoming more economical; and 2) the time in which a gas-fueled resource could be built was much shorter compared to other resources.

Since 2004, the addition of gas-fueled resources has settled into a stable rate of growth, averaging around 3 GW of growth annually. With the addition of 2.3 GW of new gas-fueled resources in 2012, the Western Interconnection has over 100 GW of gas-fueled capacity connected to the system. Overall, the gas-fueled capacity increased 150 percent since the year 2000 and is expected to continue at roughly a 3 percent annual growth rate.

Figure 9: Wind-Fueled Nameplate Capacity Additions: 2000 to 2012

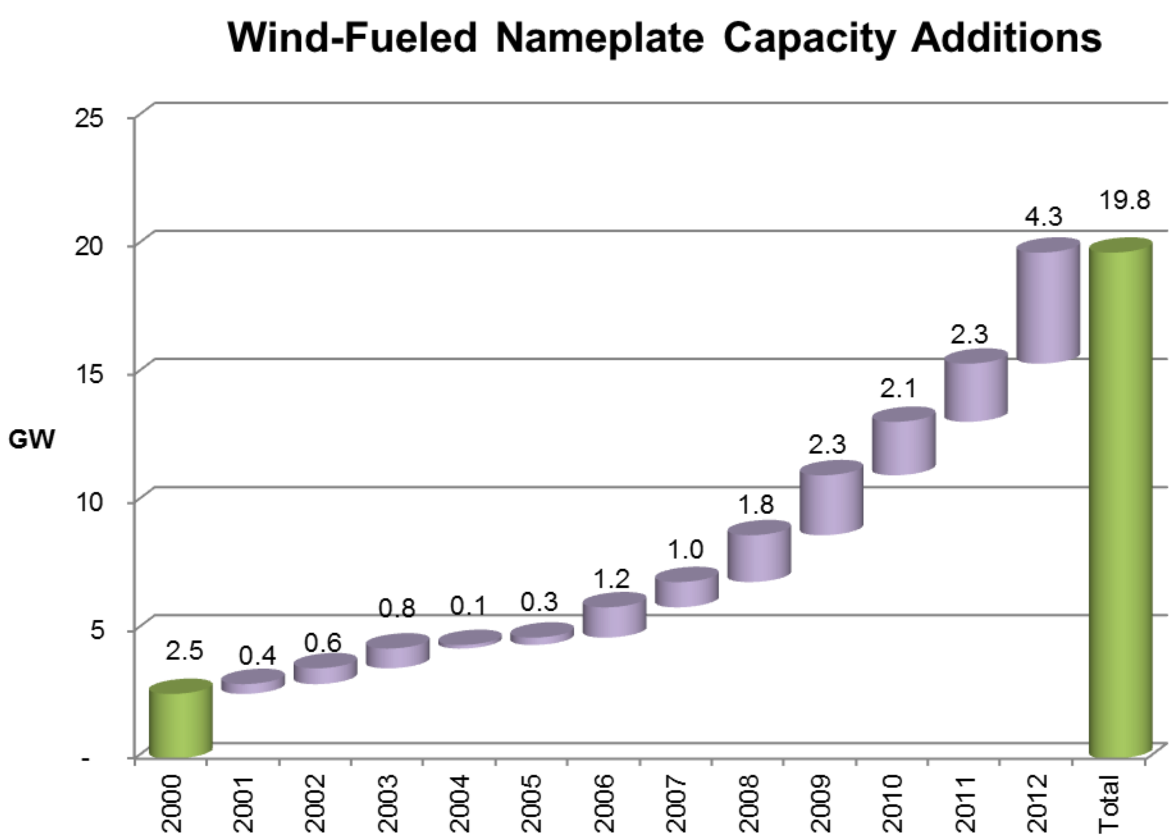


Figure 9 shows the annual growth of the wind-fueled resources since 2000. Similar to gas-fueled resources, the wind-fueled resources have experienced a significant increase in capacity; however, the majority of this growth has been in the last six years due to government policies. The wind-fueled capacity portfolio increased almost 700 percent since the year 2000 with an extraordinary 28 percent growth in 2012. At the end

[12] Federal Energy Regulatory Commission (FERC): Addressing the 2000-2001 Western Energy Crisis http://www.ferc.gov/industries/electric/indus-act/wec.asp

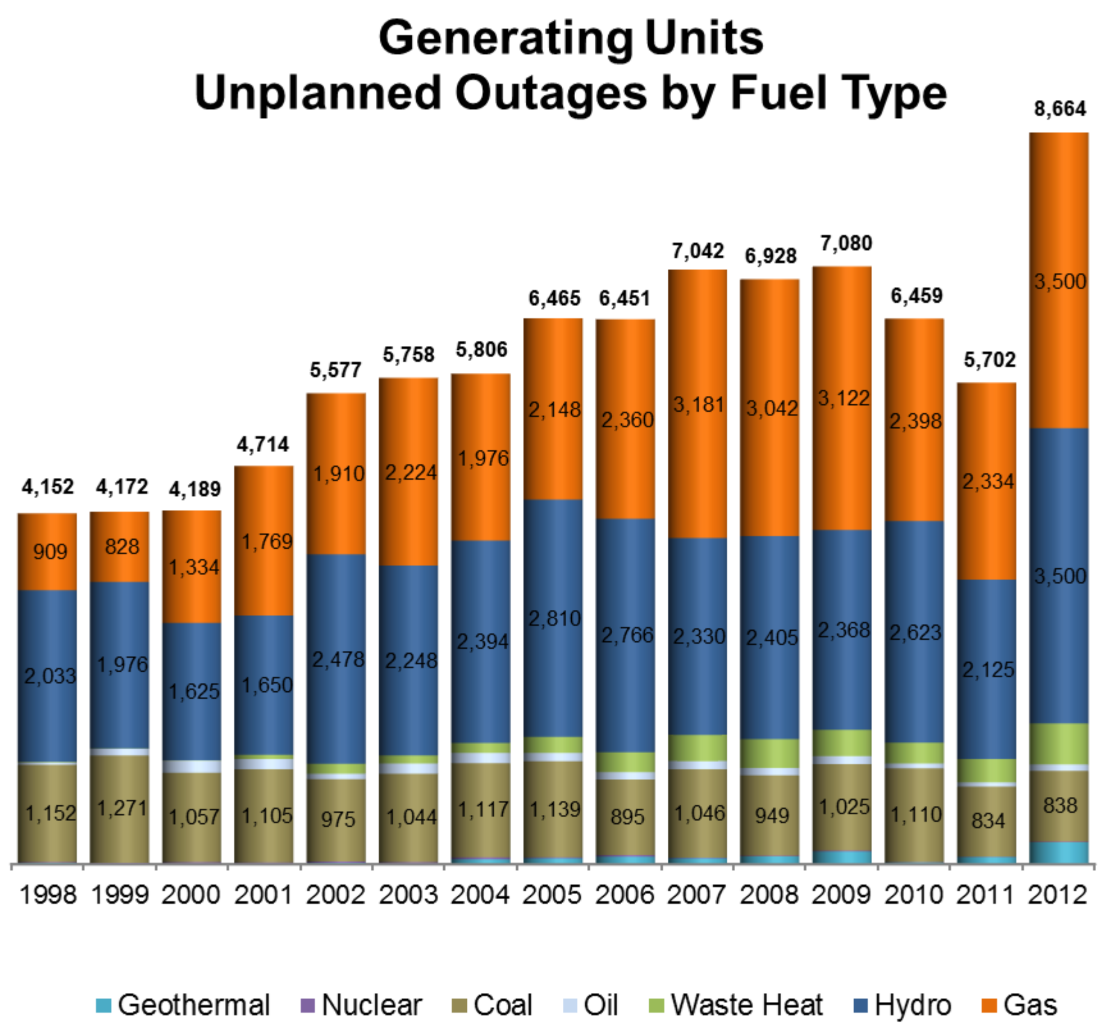
of the year, wind-fueled resources accounted for approximately 6 percent of the Interconnection-wide total capacity.

While the annual growth rate is not expected to continue at these levels, more wind resources are expected. As the portfolio has changed significantly in recent years, further analysis of the impact that the changing resource mix will have on overall system reliability is necessary. This can be done by analyzing historical generation operating data.

Observations

Figure 10 below represents the frequency of unplanned outages by generating fuel type in the Western Interconnection over the previous 15 years. The data shows a growing number of unplanned outages, mostly driven by gas resources.

Figure 10: Unplanned Outages, by Fuel Type

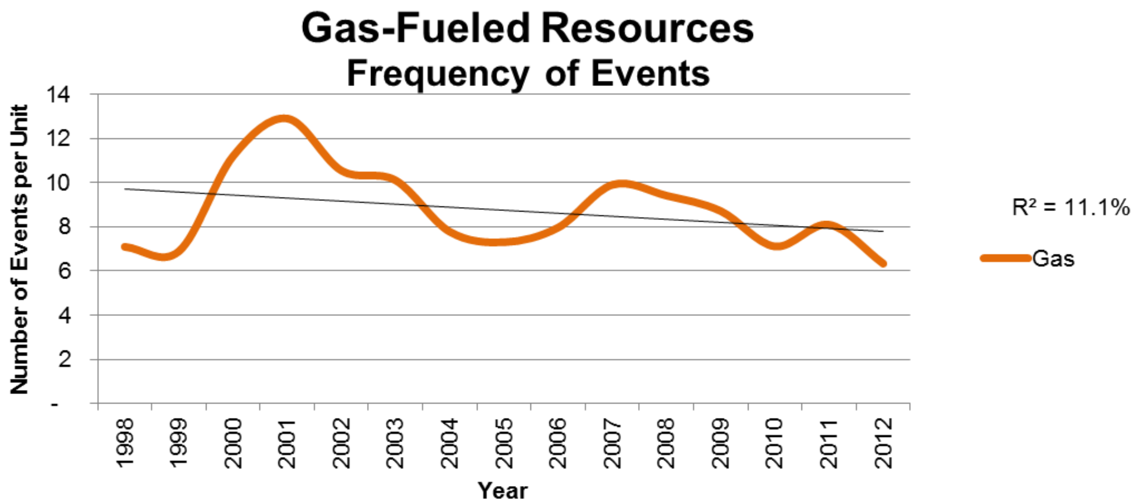


The three leading fuel resources for unplanned outages are gas, hydro and coal; however, this is primarily due to the large portion of the overall portfolio in these categories (see Figure 7).

Frequency of Events – Gas-Fuel Type

Generating resources that fall within the gas-fuel type category experienced the largest increase in the number of outages. However, Figure 11 illustrates that if the number of unplanned outages are averaged over the number of generating resources in the portfolio, the results portray a different story. The frequency of outages per generating unit has actually been decreasing since 2001.

Figure 11: Gas-Fueled Resources, Frequency[13]



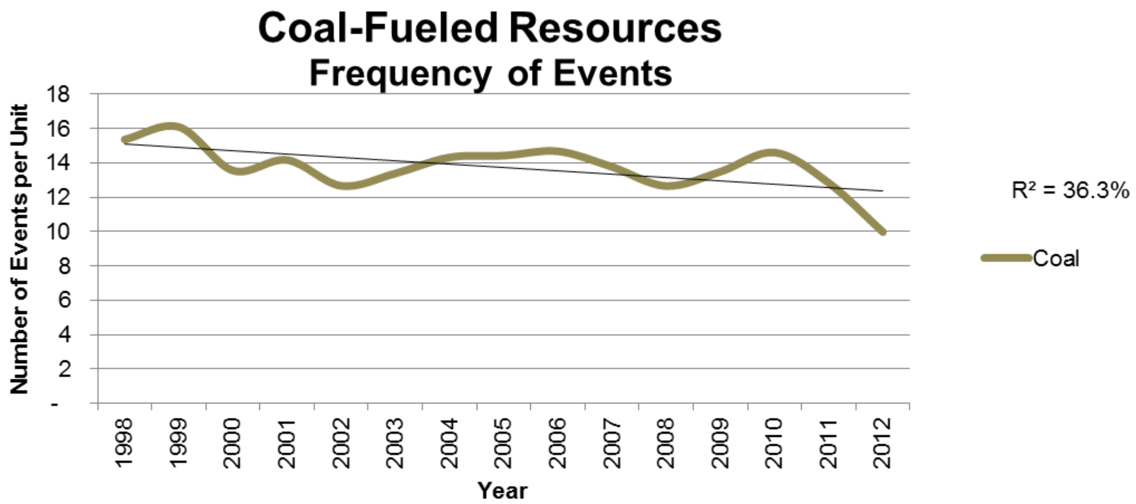
An analysis of the gas-fueled resources shows that, although relatively small, when a resource was in its infant years of generation, there was a negative correlation between the frequency of unplanned outages and the years of service. This means new resources do experience a higher number of unplanned outages during the early years of service; however this number decreases as operations stabilize. The relatively young age of the gas-fueled fleet in the Western Interconnection explains the decrease in the frequency of unplanned outages.

Frequency of Events – Coal-Fuel Type

Figure 12 reveals the average frequency per unit of unplanned outages in coal-fueled resources has historically been relatively stable. However, the most recent year of data, 2012, did see an overall decline in unplanned outages as compared to previous years.

[13] The coefficient of determination (R^2) is illustrated on many of the charts. R^2 describes how well a line represents the given data. The closer the R^2 value is to 100 percent, the higher chance that future data points will fall upon that line.

Figure 12: Coal-Fueled Resources, Frequency



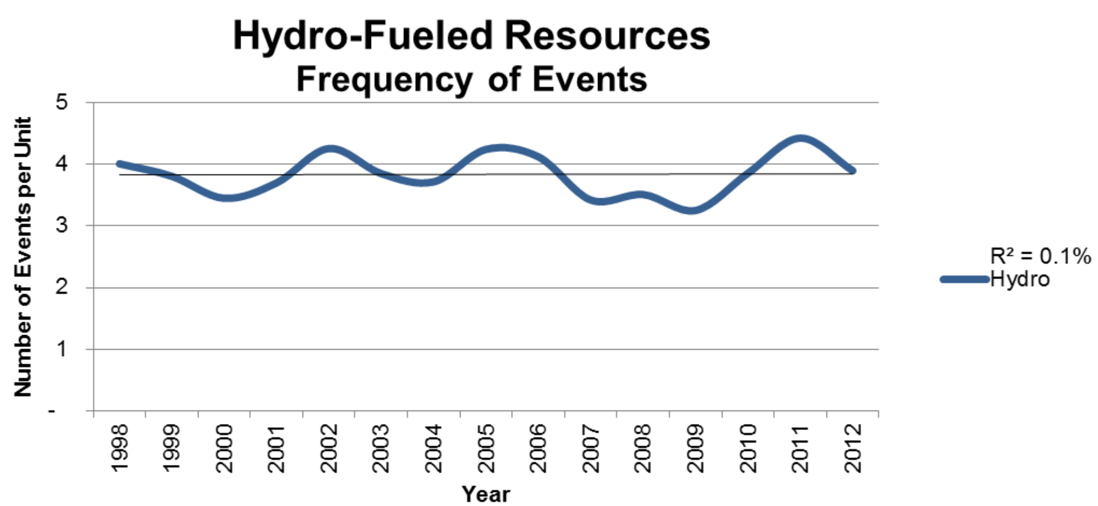
Coal-fueled resources will be watched in the years to come to see if the average trend has truly decreased or if 2012 was just a better operating year than previous years. Further analysis of inventory updates and maintenance performed is needed to understand if an increase in the frequency of planned maintenance may be contributing to the decrease in unplanned outages.

Frequency of Events – Hydro-Fuel Type

The hydro-fueled resources represent the oldest units in the Western Interconnection. An analysis concluded there was no correlation between the age of a unit and the frequency of unplanned outages experienced by the hydro-fueled resources.

Figure 13 reveals that over the previous 15 years, the average frequency of unplanned outages of hydro-fueled resources has remained relatively stable.

Figure 13: Hydro-Fueled Resources, Frequency

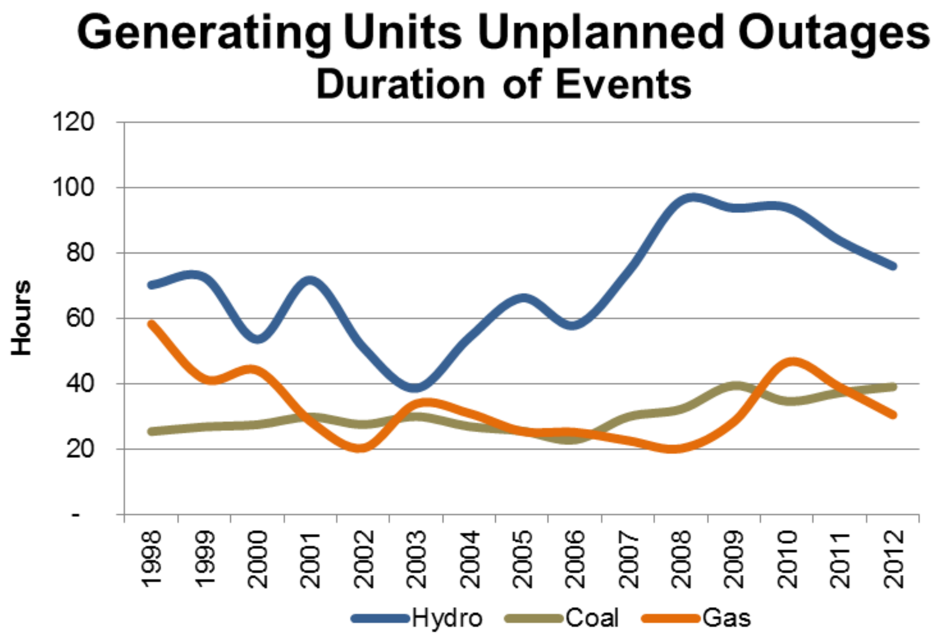


Prior to 2013, only units greater than or equal to 50 MW were required to report to GADS; however, beginning in 2013 the requirement applies to any unit greater than or equal to 20 MW. It is expected that this will result in the hydro-fuel type experiencing a large increase in the number of resources reporting due to the smaller average size of hydro-fuel type units as compared to coal and gas fueled resources.

Duration of Events

The second component of reliability metrics is that of duration. Figure 14 represents the average duration of unplanned outages for the three leading fuel types.

Figure 14: Gas, Coal and Hydro, Unplanned Outages



The data reveals hydro-fueled resource outages last longer on average than the typical coal- or gas-fueled resource outage. In 2012 alone, hydro-fueled outages lasted almost three times longer. One reason for the longer return is that most hydro plants have more than one generating unit and a fixed amount of fuel supply, therefore the urgency to sync to the grid immediately following an outage is not as great as other types of fuel resource generating units.

Further analysis will be done to determine if the geographical locations of these resources and the ability to access them has an effect on the duration.

Summary and Recommendations

Although the Western Interconnection has experienced an increase in unplanned generation outages in recent years, the addition of new resources is the driving factor to this increase. The overall frequency per unit has declined or remained stable across the fleet, decreasing the risk to reliability of the Bulk Electric System.

Coal-fueled resources will be watched in future years to determine if the decrease represented in the 2012 data is a trend, or if 2012 was just a better operating year than previous years.

Further analysis is planned to determine why some fuel type resources experience longer outage durations than others. Additional analysis is also needed to determine if the time of year, day, or even day of the week an outage occurs influences the duration of the outage.

Transmission System Availability

The Transmission Availability Data System (TADS)[14] is a NERC database used to collect transmission inventory and outage data for transmission elements greater than 200 kV. This data is valuable in developing transmission metrics that analyze outage frequency, duration, causes and many other factors related to transmission outages. For this report, WECC staff used this data to analyze frequency and duration of unplanned outages as a measure of risk to reliability in the Western Interconnection.

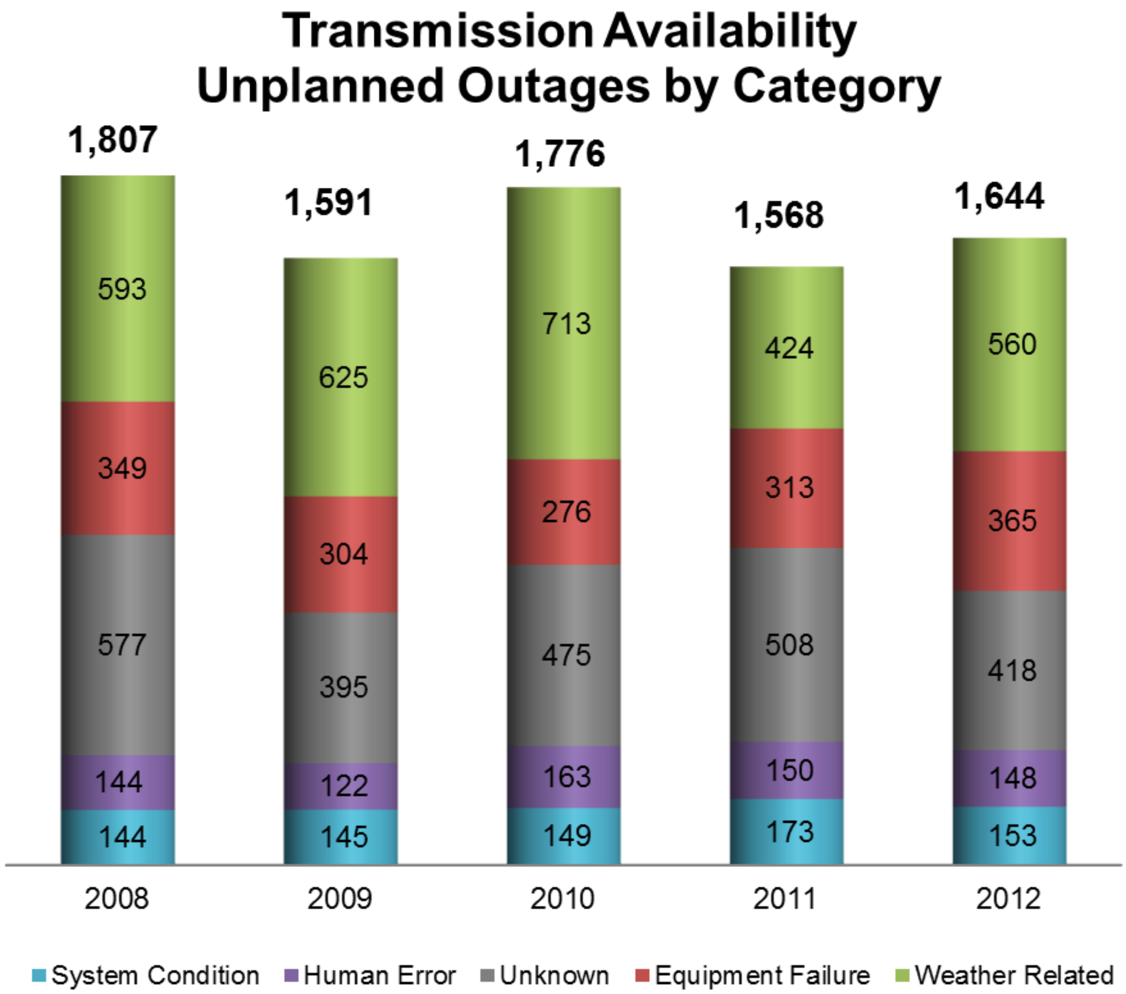
To assist with the analysis of TADS outages, WECC staff created five WECC Outage Cause Categories. The WECC Outage Cause Categories are Equipment Failure, System Conditions, Human Error, Weather Related and Unknown. These categories are a condensed version of the 17 TADS Initiating Cause Codes. The benefit of the condensed version allows events to be grouped into similar categories for the purpose of determining trends and correlating with other datasets. Specifically, WECC staff continues to create a one-to-one correlation between the WECC Outage Cause Categories and the WECC Event Analysis Categories.

Observations

Figure 15 represents the frequency of unplanned (automatic) transmission system outages by WECC Outage Cause Categories since 2008.

[14] Transmission Availability Data System (TADS): http://www.nerc.com/pa/RAPA/tads/Pages/default.aspx

Figure 15: Transmission Availability, Unplanned Outages by Category

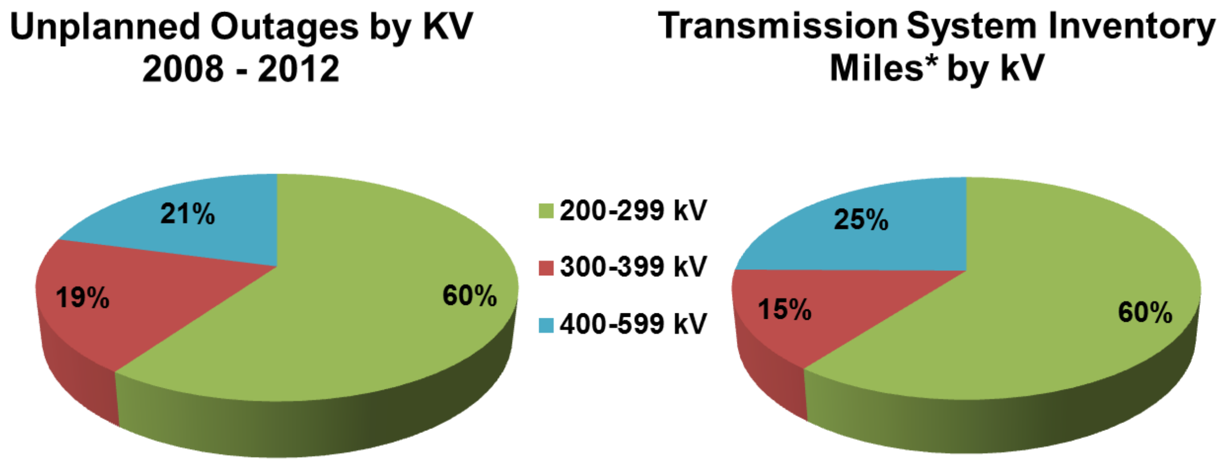


The data shows the Western Interconnection has experienced a steady number of unplanned transmission outages, neither increasing nor decreasing, since mandatory data collection began in 2008. The largest contributor to these outages continues to be Weather Related followed by Unknown, which represents outages where the initiating cause code could not be determined or the outage was corrected so quickly that no investigation into the cause was ever initiated. Of the three remaining categories, Equipment Failure remains the largest.

<u>Tranmission Line Size</u>

Figure 16 illustrates unplanned transmission outages grouped in 100-kV levels compared to the transmission system inventory miles by kV.

Figure 16: Unplanned Outages and Transmission System Inventory, 2008-2012, by kV

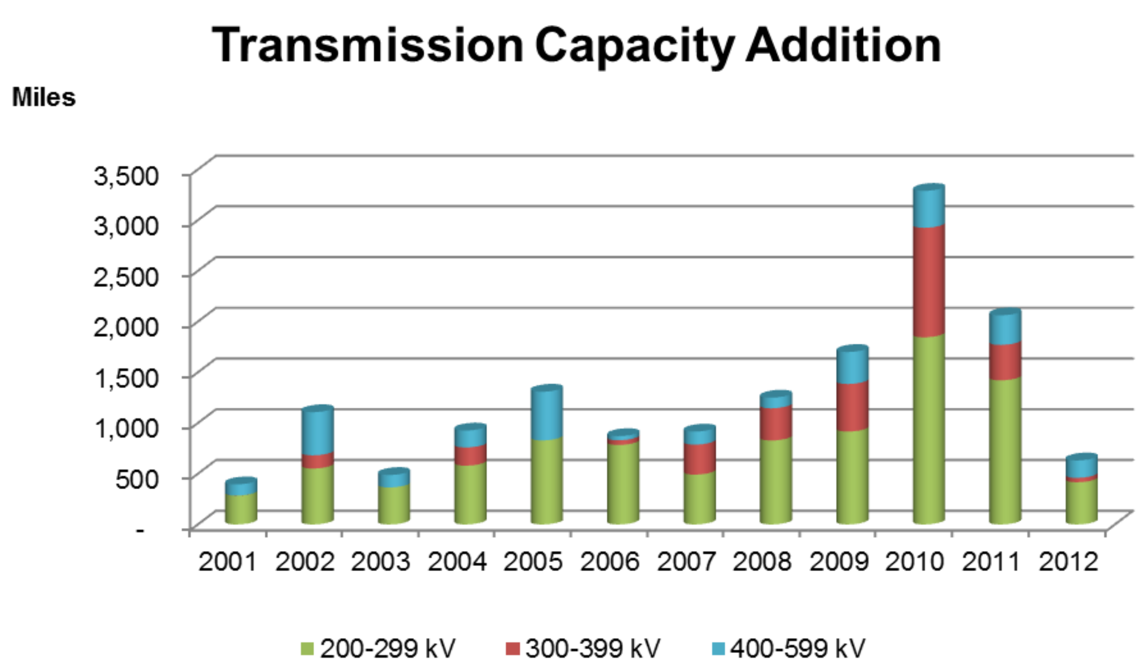


*The Transmission System Inventory data only reflects inventory collected by TADS. Currently, TADS only collects inventory for 200-kV lines and greater.

The chart shows that the majority of unplanned outages, 60 percent, occur on the lower voltage transmission lines at the 200- to 299-kV level. This is directly correlated with the overall inventory of transmission miles by transmission line voltage. The pie chart on the right in Figure 16 exhibits that the transmission portfolio in the Western Interconnection is heavily weighted toward the lower voltage 200- to 299-kV lines with 60 percent of the roughly 75,000 total miles.

Figure 17 shows the addition of TADS transmission mileage in the Western Interconnection by kV voltage class since 2001.

Figure 17: Transmission Capacity Addition

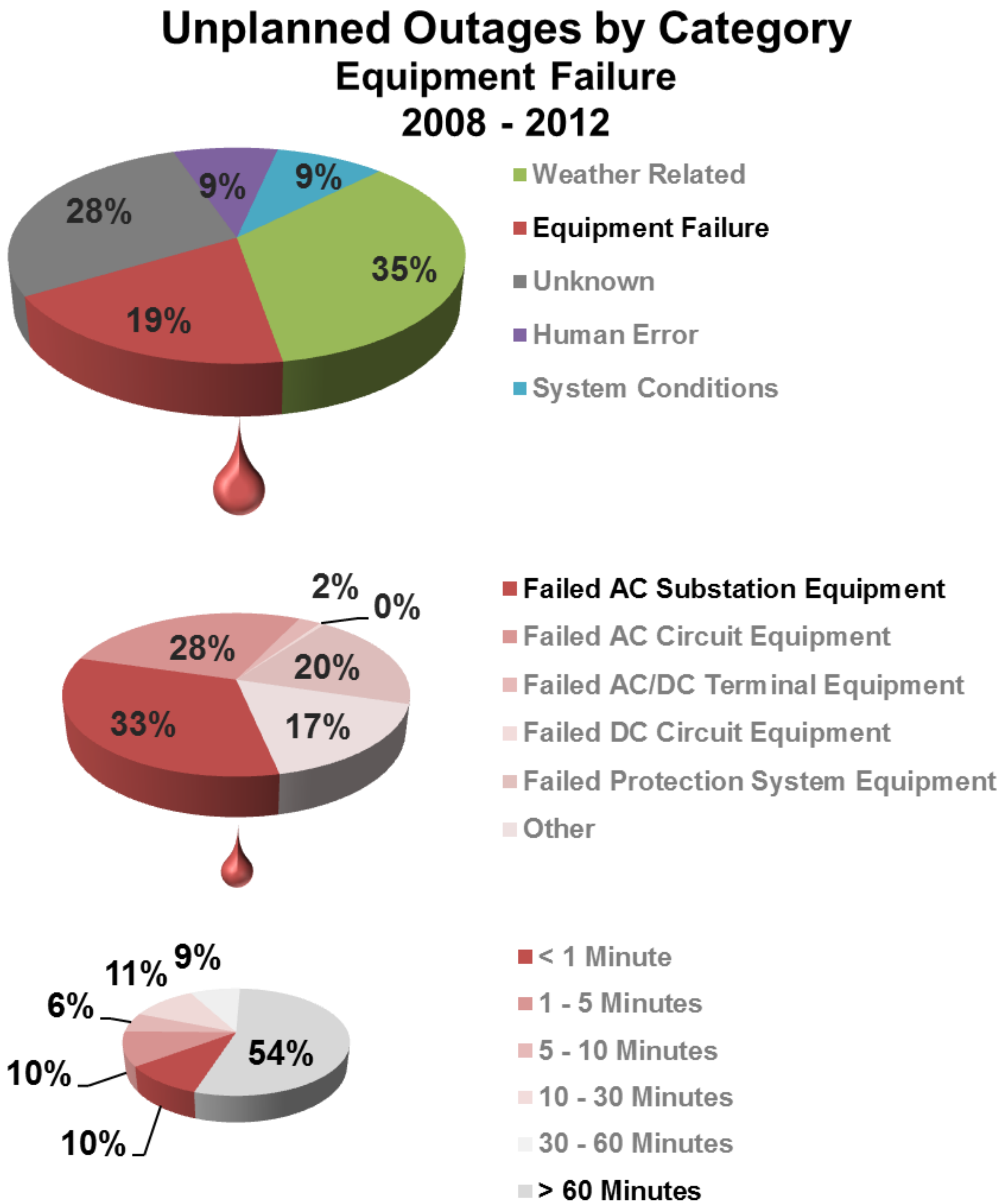


The 200- to 299-kV lines continue to add the most miles to the system each year which demonstrates the need of the Western Interconnection to transfer energy within its growing urban areas. The current year, 2012, experienced a significant decrease in the miles added to the system compared to the previous five years. In 2012, the Western Interconnection added just over 600 miles of new transmission, an increase of less than 1 percent. When compared to the peak in 2010 of nearly 3,200 miles that caused an almost 5 percent increase in the portfolio mileage, 2012 was relatively quiet. With the significant addition of new transmission miles over the last five years, the transmission failure contribution as a risk to reliability needs to be analyzed. To do this, annual transmission unplanned-outage data can be analyzed to see if the frequency and duration of the outages has changed over the same period of time.

Unplanned Outages – Equipment Failure

Equipement Failure accounts for nearly 20 percent of all TADS unplanned outages, approximately 300 outages annually. Figure 18 details the subcategories of Equipment Failure through the use of a drop diagram. The first pie chart represents the five WECC Outage Cause Categories, while the second chart shows the TADS Initiating Cause Code and reveals that failed AC-substation equipment accounts for a third of all Equipment Failures, approximately 100 failures in the Western Interconnection, annually.

Figure 18: Unplanned Outages by Category, Equipment Failure



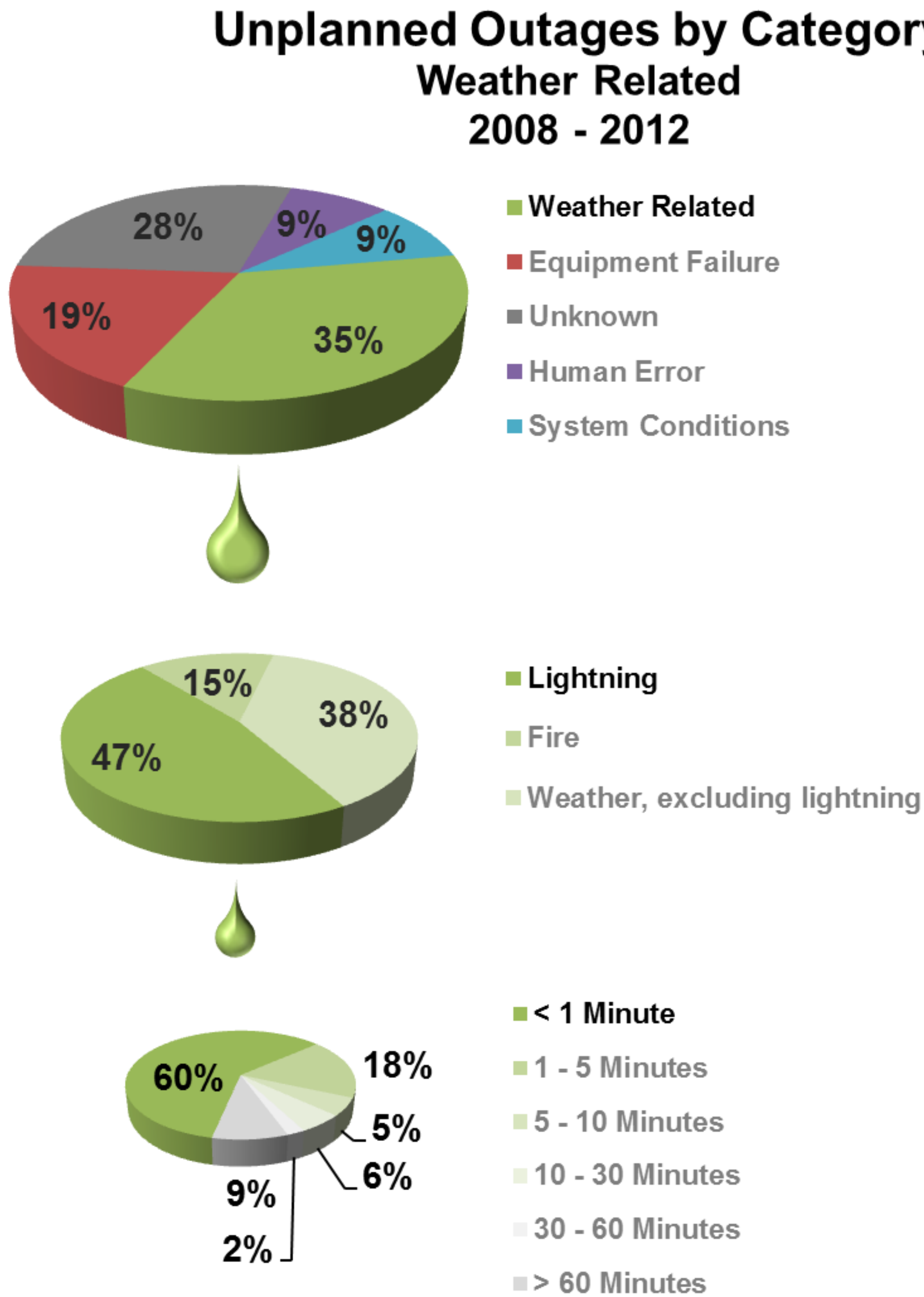
The third pie chart reveals that over half of the AC-substation Equipment Failures lasted longer than one hour. Typically, these types of outages take longer to repair and the longer duration increases the risk of load loss.

Since TADS tracks transmission element inventory as well as outages, further analysis can be done on the components of the Failed Equipment to determine if these outages can be correlated with the age of the equipment, geographical region or physical attributes. Once the additional analysis is complete, recommendations to reduce risk to reliability can be provided.

Unplanned Outages – Weather Related

Figure 19 illustrates a drop diagram for the largest number of unplanned outages for a TADS cause category, Weather Related.

Figure 19: Unplanned Outages by Category, Weather Related



Representing 35 percent of all TADS unplanned outages since 2008 or approximately 600 outages annually, the TADS initiating cause codes represented in the second pie chart reveal that almost half of the Weather Related outages were caused by lightning.

Lightning is one of the largest drivers of unplanned outages and, although it cannot be controlled, efforts can and have been made to prepare for such outages. The third pie chart reveals nearly two-thirds of these outages lasted less than a minute indicating the transmission system responded as designed and limited the impact of these outages. From 2008 to 2012, only 11 percent of the lightning-caused outages lasted longer than 30 minutes.

Given the large geographical territory of the Western Interconnection, further analysis of the Weather Related outages should be conducted. Findings may provide recommendations for reducing risk to relaibility in cases of Weather Related outages.

Summary and Recommendations

The unplanned transmission outages occurring in the Western Interconnection continue to remain constant. Many of the outages are Weather Related, but the duration of these outages is relatively short, indicating the system is operating as designed. As mentioned earlier, given the large geographical footprint of the Western Interconnection, further geographical studies could ascertain where Weather Related outages are more likely to occur and provide valuable insight in avoiding longer duration outages.

Also, analysis is needed to determine how physical attributes (e.g., structure type, insulator type) influence line performance in relation to Equipment Failure outages.

Finally, continued effort will be made to gather more meaningful results from the frequency of outages per transmission line size.

Event Analysis

The WECC Event Reporting and Analysis (ERA) process[15] is based on the recognition that Bulk Electric System events that occur, or have the potential to occur, have varying levels of significance. WECC's ERA principal goals are to: 1) undertake appropriate levels of analysis to determine the causes of the events; 2) promptly assure tracking of corrective actions to prevent recurrence; and 3) provide lessons learned to the industry.

The WECC ERA process does not preclude adherence with the Department of Energy (DOE-OE-417) or the EOP-004 NERC reporting requirements.

Background

The current WECC ERA process was established to align with the NERC Event Analysis Process (EAP)[16] adopted by NERC in February 2012. WECC disturbance reporting dates back to 1979, the event analysis website[17] contains reports submitted since 1999, and the *Totally Resolved Log,* which includes the recommendations and resolutions for events back to 1979.

---

[15] WECC Event Reporting and Analysis Process document: http://www.wecc.biz/library/Documentation%20Categorization%20Files/Guidelines/WECC%20Event%20Analysis%20Process.pdf

[16] NERC Event Analysis Process Document: http://www.nerc.com/pa/rrm/ea/EA%20Program%20Document%20Library/ERO_Event_Analysis_Process_Document_Version_1_Feb_2012.pdf

[17] WECC Event Analysis website (WECC login required): http://www.wecc.biz/library/EventReports/Forms/Event.aspx

Observations

Entities are encouraged to report the occurrence of Bulk Electric System disturbances and unusual occurrences in accordance with various NERC and WECC Reliability Standards. Disturbances and unusual occurrences can be, but are not limited to:

- Loss of 300 MW or greater of load for longer than 15 minutes.
- Loss of electric service to more than 50,000 customers for longer than one hour.
- Loss of 500 MW or greater of generation.
- Loss of a transmission component that significantly impacts the Western Interconnection.

When an event occurs, Registered Entities should do the following.

1. Make an initial assessment of the event and determine the initial event category (Category 1-5 per the NERC EAP Appendix E: Categorization of Events[18]).
2. Submit a Brief Report and plan a meeting to be held with all involved parties.
3. Confirm the category of the event at the meeting.
4. Determine if the qualifying event is Category 3 or higher. If it is, then an event analysis report (EAR) is to be submitted. An EAR may be requested for events below category 3.
5. Develop lessons learned and best practices (if any), and share them with the industry.
6. Assign NERC cause codes and close the event process.

In 2012, the Western Interconnection experienced 57 events that resulted in the submittal of a Brief Report. With detailed event reporting the third aspect of reliability, severity, can be analyzed. Of the 57 events in 2012, only 11 (~19 percent) of the reports resulted in the loss of firm load. This is equal to the annual average number of events with a loss of firm load since the year 2000.

WECC Event Analysis Cause Categories

To better analyze EAR, WECC Operating Specialists created four WECC Event Analysis Cause Categories by aggregating the NERC EAR cause codes. The categories are:

- Equipment Failure – Failure of Bulk Electric System or Energy Management Systems (EMS) equipment.
- System Conditions – Generation or line loss, an overloaded element or an EMS evacuation.
- Human Error – Design and relay setting errors, Relay testing errors and following written procedures.

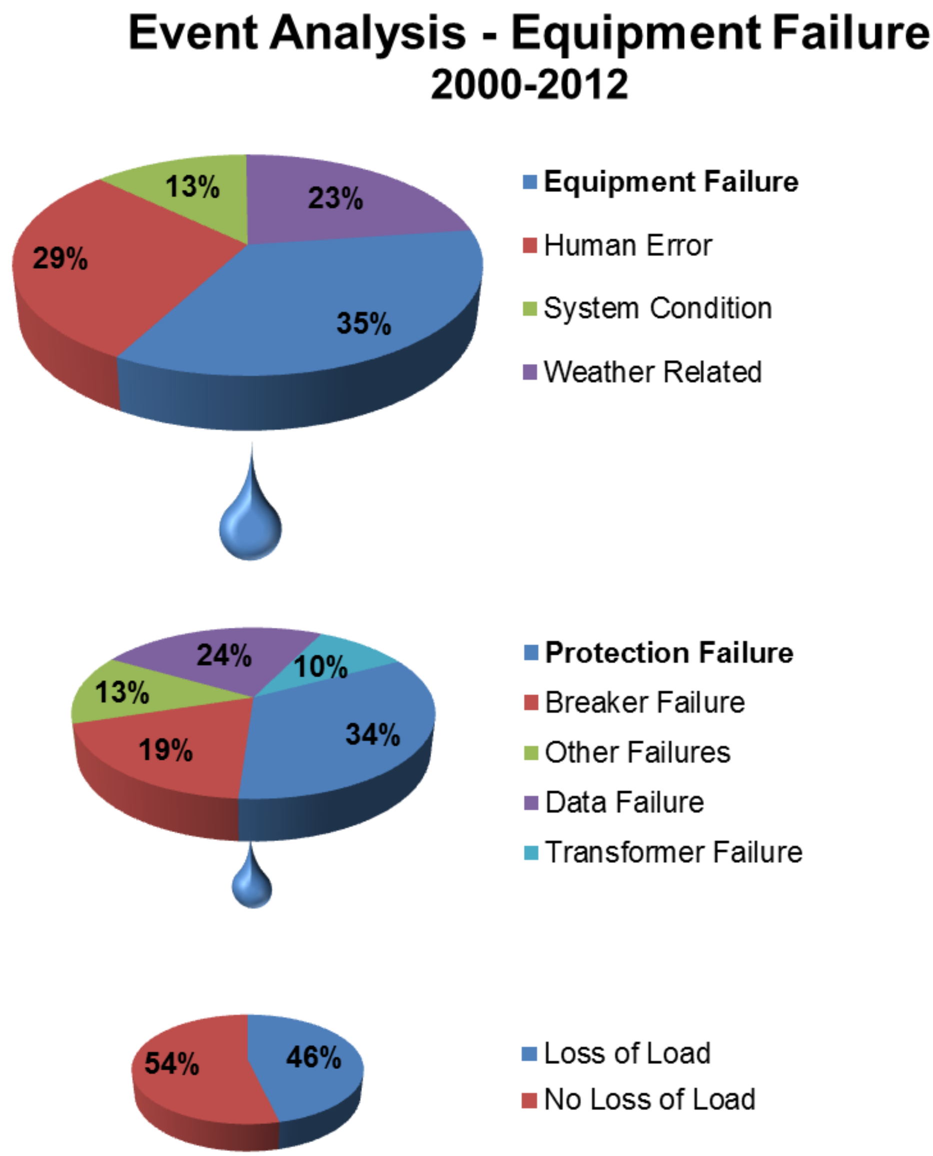
[18] NERC Event Analysis Process Appendix E: Categorization of Events http://www.nerc.com/pa/rrm/ea/EA%20Program%20Document%20Library/Appendix%20E%20-%20Categorization%20of%20Events.doc

- Weather Related – Fire and Lightning caused, Extreme temperature and wind caused and events caused by earthquakes.

These cause categories are a summary version of the NERC Event Analysis Cause Coding. The benefit of the aggregated WECC Event Cause Categories is that they can help determine trends and be correlated with other datasets.

Figure 20 is a drop diagram of the WECC Event Cause Categories since the year 2000.

Figure 20: Event Analysis, Equipment Failure

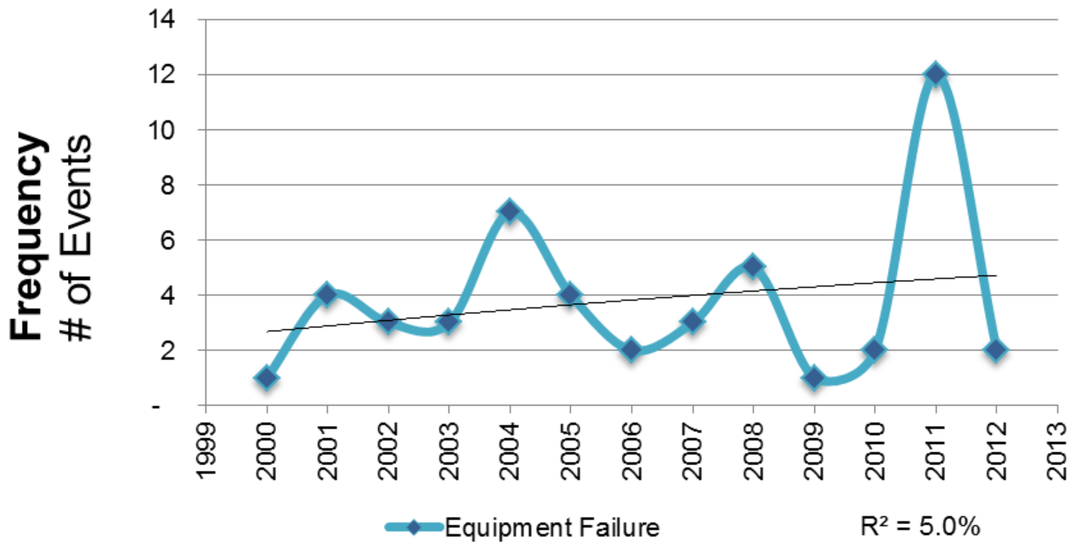


The diagram shows Equipment Failure events continue to be the largest category, making up approximately one third of all events that required an EAR. The second pie chart of the drop diagram shows the subcategories of the Equipment Failure, events classified as initiated by Protection Failure continue to be the leading cause of events, followed closely by Data Failure and Breaker Failure caused events. Finally, the third pie chart reveals that approximately half of the Protection Failure events led to the loss of firm load.

Frequency of Events – Equipment Failure

Figure 21 reveals the annual frequency of Equipment Failure events with the loss of firm load since the year 2000.

Figure 21: Equipment Failure, Frequency



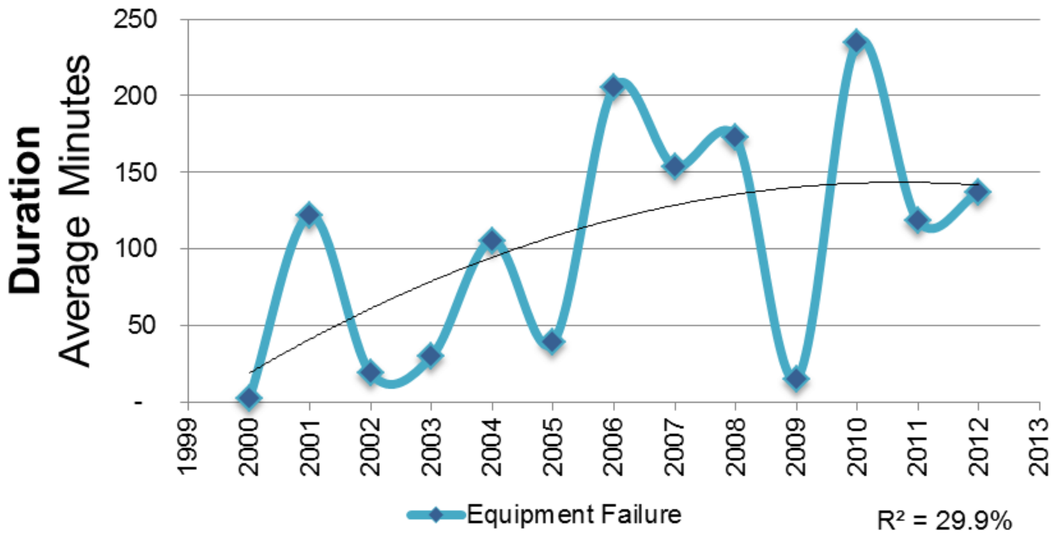
The number of events fluctuates between 1 and 12 events; however there is no clear trend. The trend line barely explains 5 percent of the data and cannot be used to predict what the Western Interconnection should expect in the years to come.

Equipment Failure continues to be a major contributor to the frequency of events that result in EARs. Analyzing their impact by reviewing Equipment Failures duration and severity is needed to understand the overall risk to reliability of the Western Interconnection.

Duration of Events – Equipment Failure

Figure 22 reveals the average duration of Equipment Failure events since the year 2000.

Figure 22: Equipment Failure, Duration

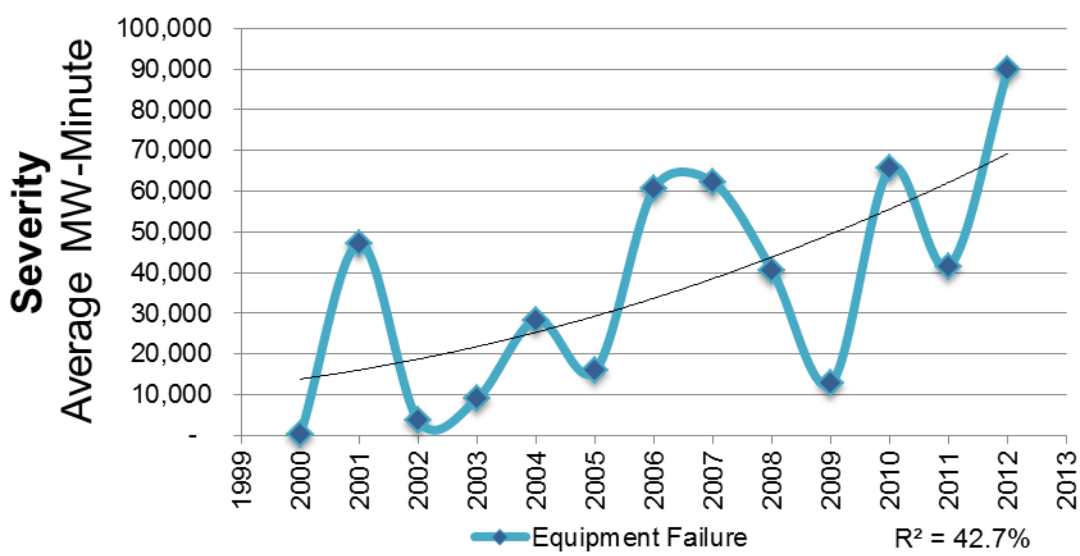


The data shows the average duration of these events continued to increase over this time period. As the duration of events increases, more loss of firm load is experienced, reducing the level of reliability in the Western Interconnection. According to the trend line, there is a 30 percent chance that the average duration has begun to plateau around the two-hour mark, but the data will need to be monitored in future years to see if this trend continues.

<u>Severity of Events – Equipment Failure</u>

Figure 23 reveals the average severity, or the loss of firm load, of the Equipment Failure events since the year 2000.

Figure 23: Equipment Failure, Severity



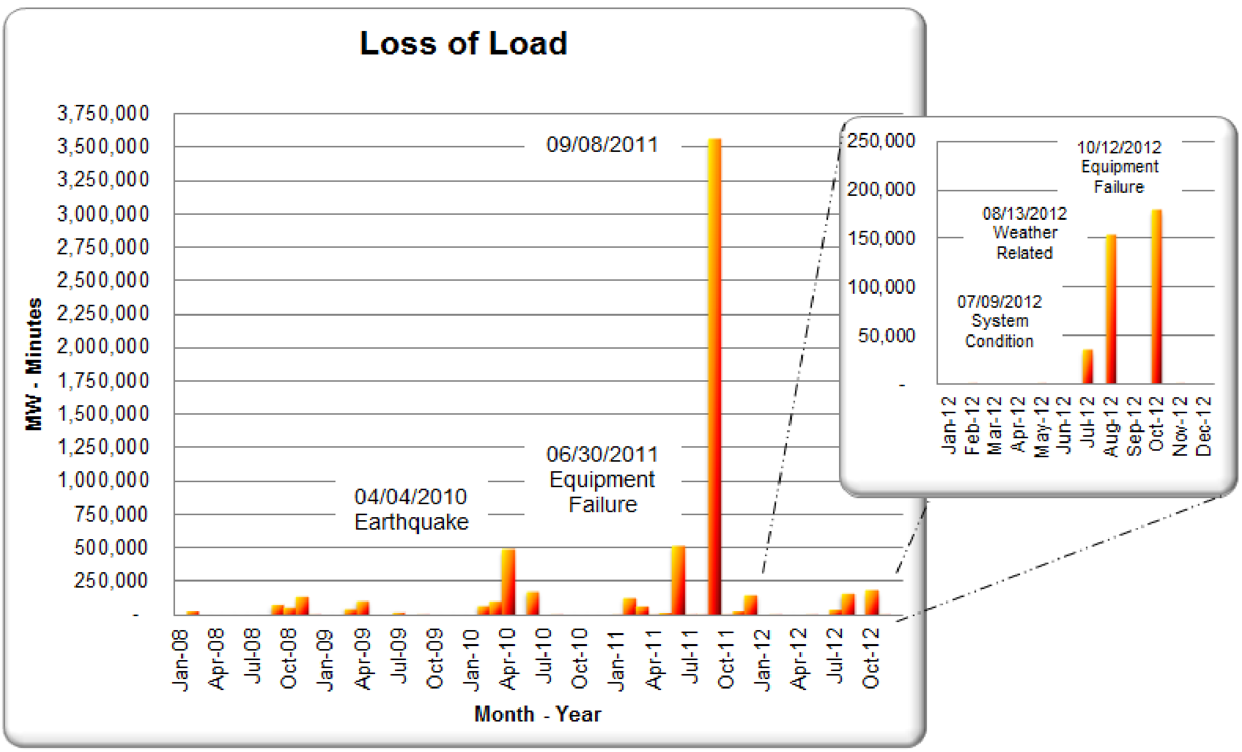
Although the frequency of events is relatively low and the average duration seems to have plateaued, there is a 40 percent chance that the overall impact of these outages is continuing to increase. Given the loss of firm load is calculated based on the MW of load lost multiplied by the duration of the event, if the duration remains the same, this means these events are impacting a larger number of MW and a larger number of customers. Further analysis is needed of the EARs to understand why this is occurring. If the severity was normalized using total load demanded by the system at the same time, would the trend continue to grow? Are Equipment Failures beginning to occur in more densely populated areas? Is there a certain type of equipment that is beginning to fail which has a larger impact to the system? All of these questions need to be analyzed further in future State of the Interconnection reports.

Loss of Load Comparison

Although focusing the analysis on the individual category that continues to have the largest impact on reliability depicts a less reliable system, when all loss of load events are looked at in total, overall, 2012 was a better reliability performance year than previous years.

Figure 24 reveals there were three significant events of loss of firm load in the Western Interconnection in 2012.

Figure 24: Loss of Load Comparison



The three significant Bulk Electric System events in 2012 were: 1) a system-condition event in July that impacted roughly 35,000 MW-minutes; 2) a high-wind event in August impacting just over 150,000 MW-minutes; and 3) an Equipment Failure event in October that impacted nearly 180,000 MW-minutes. These events are less than some of the major events of previous years, especially when compared to the Southwest Blackout that occurred on September 8, 2011. Further analysis is needed to determine a threshold to measure what a sustainable level of reliability is, but given the events over the last five years, a benchmark of 250,000 MW-minutes appears to be a reasonable amount of load loss for an event to be categorized as major.

Lessons Learned

Another contribution to the EAR process is the sharing of lessons learned with the industry.

Again, to assist with analyzing of the event reports WECC Operating Specialists have created several WECC Lessons Learned Categories. The categories are:

- Communications Issues – Inadequate communication between workers or contractors.
- Maintenance Issues – Inadequate maintenance procedures or practices.
- Design issues – Inadequate design or more input during the design process.
- Outage Planning – Inadequate assessment and planning of the task.
- Equipment Issues – Inadequate equipment or wrong application of equipment.
- Procedure Changes – Inadequate written procedure.

Entities submitted six Lesson Learned reports in 2012. One of the Lessons Learned indicated that the event might not have occurred if the entity had communicated its work practices to the contractor. Typical industry best practices during the designing process could have mitigated two lesson learned events. Finally, better understanding of software or equipment upgrades and documenting a start-up procedure may have reduced the EMS Loss of Visibility outage time for three lesson learned events.

WECC members can access the Event Analysis Reports and Logs website to read the detailed Lessons Learned reports.[19]

Summary and Recommendations

There were three significant EAR load loss events in 2012, but the overall load lost due to these events was relatively small compared to events in 2010 and 2011. Equipment Failure continues to be the largest category of EAR events and the overall severity of these events has been increasing in recent years, leading to a needed analytical focus.

Further analysis of the break out of the WECC Event Analysis Cause Categories can be conducted to determine which, if any, categories and subcategories have a higher percentage of load loss associated with them.

Additional discussion of the appropriate threshold to measure a reasonable level of reliability in regards to loss of load is also needed.

Protection System Misoperations

An important aspect of reliability to the Bulk Electric System is the correct performance of Protection Systems, which have been defined by NERC as:

- Communications systems necessary for correct operation of protective functions;
- Voltage and current sensing devices providing inputs to protective relays;

[19] Event Analysis Reports and Logs website : http://www.wecc.biz/library/EventReports/Forms/ReportsOther.aspx

- Station DC supply associated with protective functions (including batteries, battery chargers, and non-battery-based DC supply); and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

Misoperations are the result of protection relays not functioning as intended and can have a significant impact on the Bulk Electric System. When the Protection System fails to operate during a Fault or operates for a non-Fault condition, a misoperation of the Protection System has occurred. NERC has found that nearly all major system events, excluding major weather events, have had a misoperation contribute a multiplying[20] effect to the impact of the event.

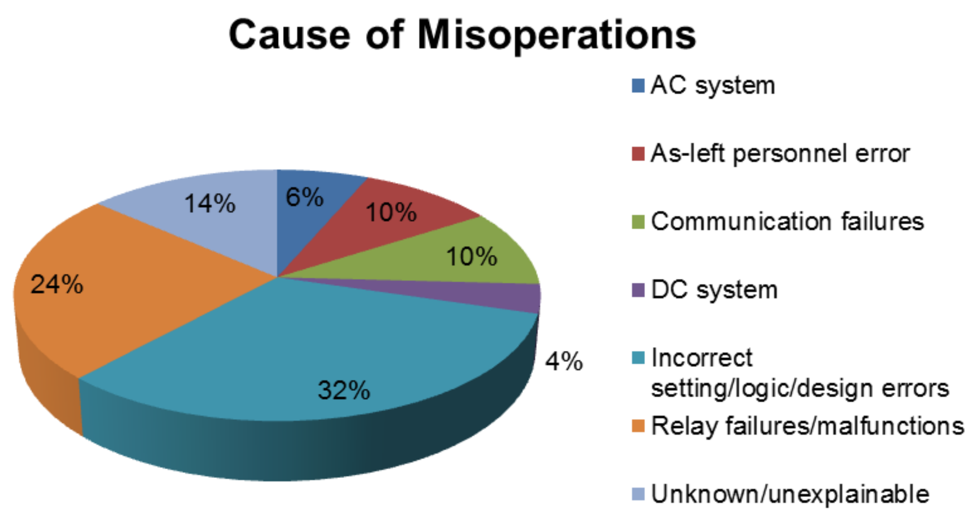
Monitoring Bulk Electric System Protection System events, as well as identifying and correcting the causes of misoperations, will improve Protection System performance.

In 2010, NERC developed a standardized process for the Regional Entities to use in collecting and monitoring misoperation data. Reporting using the newly developed process began in the third quarter of 2011. The collection of data over several years will be necessary to identify significant trends, but the data collected to date can highlight several preliminary findings and observations.

Observations

Misoperations can be classified under seven NERC cause categories. Figure 25 reveals that the largest cause of 2012 misoperations is "Incorrect setting/logic/design errors."

Figure 25: Cause of Misoperations



This cause category includes misoperations due to human errors including setting errors, errors in documentation, and errors in the design of the protection application. The NERC Protection System Misoperations Task Force (PSMTF) suggests several techniques for mitigating misoperation due to incorrect setting/logic/design. These

[20] http://www.nerc.com/docs/docs/blackout/BlackoutTable.pdf

techniques include peer review, training, fault studies, and standard templates for setting schemes.[21]

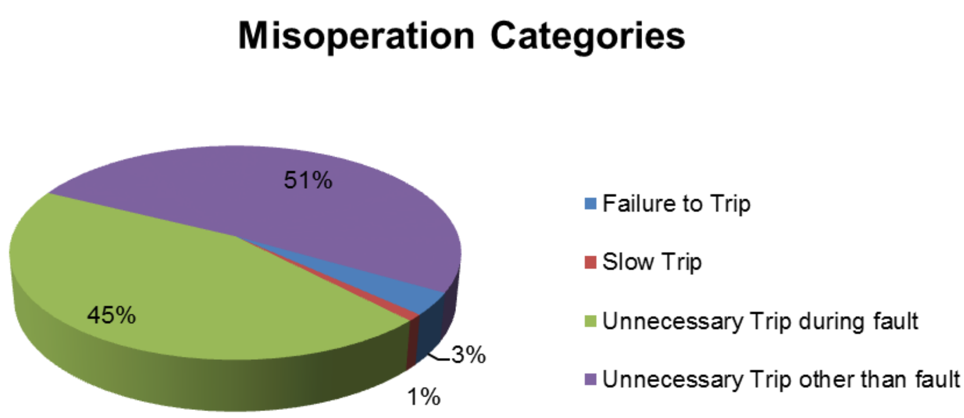
While Protection Systems cannot prevent all events within the zone they are designed to protect, overall protection designs can mitigate these events by backup protection designs.

Misoperations are currently classified into four groups reflecting how the protection system operated. The four categories are:

- Failure to Trip – A failure of a Protection System to operate for a Fault or non-Fault within the zone it is designed to protect.
- Slow Trip – A Protection System operation that is slower than intended for a Fault or non-Fault within the zone it is designed to protect.
- Unnecessary Trip During Fault – A Protection System operation for a Fault for which the Protection System is not intended to operate.
- Unnecessary Trip Other than Fault – A Protection System operation for a non-Fault condition for which the Protection System is not intended to operate, and is unrelated to on-site maintenance, testing, inspection, construction or commissioning activities.

Figure 26 shows the percentage of Protection System misoperations that are caused by each of the categories listed above.

Figure 26: Misoperation Categories



Summary and Recommendations

Incorrect settings/logic/design errors continue to drive the misoperation of Protection Systems. Failure to Trip and Slow Trip are a very small portion of the events, with almost all of the misoperations categorized under either an Unnecessary Trip During a Fault or Unnecessary Trip Other Than Fault.

[21] PSMTF Misoperation Report page 3: http://www.nerc.com/comm/PC/Protection%20System%20Misoperations%20Task%20Force%20PSMTF%20D/PSMTF_Report.pdf

Further analysis will be conducted to determine a correlation (if any) between Cause of Misoperations, Misoperation Categories and Misoperation Technologies and their effect on risk to reliability.

Additionally, revision of the Reliability Standards associated with misoperations is currently underway. Once approved and implemented, changes to the definition of a misoperation and misoperation categories will occur. This will change the data being collected and delay the ability to identify trends until several years of consistent data has been collected.

Reliability Coordinator Directives

The WECC Reliability Coordinator (RC) has the responsibility, as defined in Reliability Standards, to actively monitor the Western Interconnection transmission system in real time, to identify and direct action to prevent potential threats, and to mitigate actual threats to the Bulk Electric System. The RC accomplishes this by utilizing a suite of EMS and Plant Interface tools. These tools include a combination of graphic visual displays, alarms, state estimator and contingency analysis results. When the RC detects a potential or actual emergency condition they contact the impacted entity(ies) and discuss the situation, including recommending appropriate mitigation strategies to alleviate the harmful condition. If the entity is unable to mitigate the condition or circumstances otherwise dictate a need, the RC may issue a directive to the entity. The directive specifically identifies the reliability issue, the mitigating action(s) required and the time in which the entity must complete the action(s).

Observations

In 2012 the RC acquired two tools that significantly aid in determining the most effective mitigating action(s) required to return the grid to a secure state. The first is a Network Sensitivity (NetSens) tool. This EMS application identifies which generation, phase shifters or load shed will be most impactful in mitigating an actual or potential SOL or IROL exceedance. The second tool is the Real Time Line Outage Distribution Factors (RTLODF) application. This software operates in concert with NetSens and provides awareness of key facilities and/or path flows for the loss of other facilities. As monitored facilities and/or paths increase in flow to the point of needing mitigation, the RC will be able to calculate the sensitivity factors for that path or facility which enables the RC to coordinate specific actions with the respective Transmission Operator(s) to alleviate the congestion.

These tools are key to the RC's continued 'responsibility to act' culture when managing grid reliability. Whether it is an SOL or IROL event that must be mitigated in 30 minutes or a Disturbance Control Standard (DCS) event which must be mitigated within 15 minutes, these tools provide the RC with actual actionable intelligence on what specific actions will prevent or mitigate the emergency.

Summary and Recommendations

In subsequent reports an analysis of SOL and IROL exceedances, and the root cause of RC directives, will be conducted.

Reliability Standards Violations

Reliability in the Western Interconnection is improved through compliance with the Reliability Standards. Pursuant to a Delegation Agreement with NERC, WECC is a Regional Entity as defined in Section 215 of the Federal Power Act.

On March 16, 2007, the Federal Energy Regulatory Commission (FERC) issued Order Number 693 approving Reliability Standards as mandatory and enforceable. As a Regional Entity, WECC adopted and implemented the NERC Compliance Monitoring and Enforcement Program (CMEP) to monitor, assess and enforce compliance with Reliability Standards by the users, owners and operators of the Bulk Electric System in the Western Interconnection. The CMEP is used to provide transparency, consistency and communication with regard to compliance monitoring.

In the 2011 State of the Interconnection report, an attempt was made to correlate specific Reliability Standard violations to Outage Cause Categories. Further analysis revealed that additional process development is needed before the correlation analysis can be used. Work on this process is continuing with the goal of using this analysis for the 2013 report.

The Reliability Standards are broken into two categories: Operation and Planning (O&P) and Critical Infrastructure Protection (CIP). O&P standards focus on procedures, protections systems and proper communication plans. CIP standards focus on determining and protecting the key systems and facilities of the Western Interconnection.

The CMEP provides the compliance monitoring processes used to enforce Reliability Standards. Of the seven discovery methods currently outlined in the CMEP, the three most widely used processes are:

- Self-Certification – Requires Registered Entities to self-certify their compliance with Reliability Standards.
- Self-Reporting – Self-Reporting is encouraged at the time a Registered Entity becomes aware of a potential violation of a Reliability Standard, or a change in the violation severity level of a previously reported violation.
- Compliance Audit – Compliance Audit processes conducted in the United States are based on professional auditing standards recognized in the U.S., including Generally Accepted Auditing Standards, Generally Accepted Government Auditing Standards, and standards sanctioned by the Institute of Internal Auditors. Audit processes for Compliance Audits conducted outside the U.S. may be based on Canadian or other international standards.

Observations

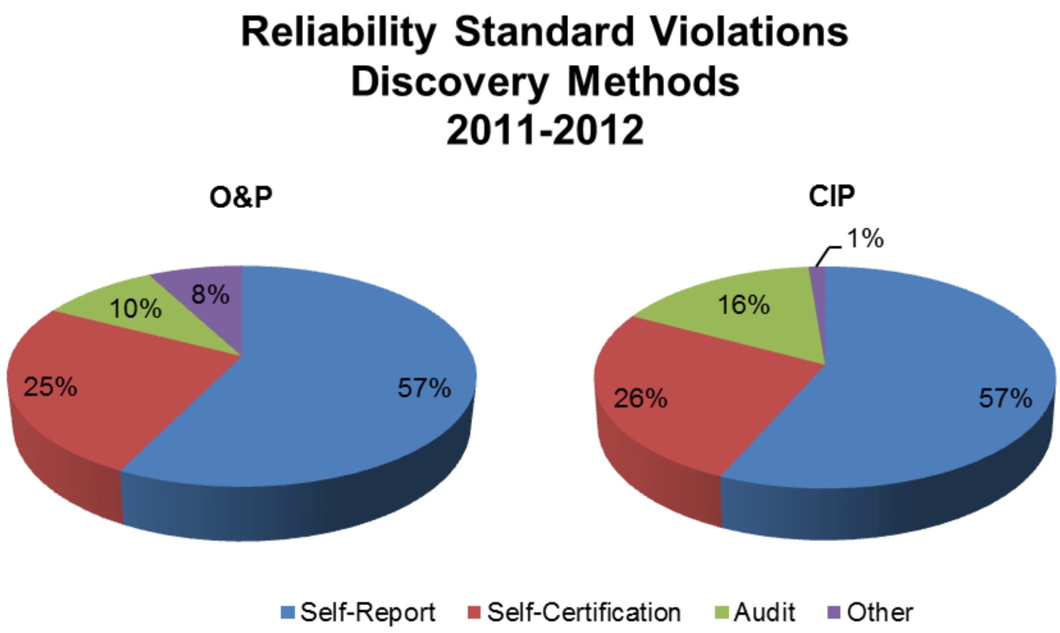
The data used for the analysis is from public and non-public Reliability Standard violations that occurred in 2011 or 2012 that have been reviewed and validated. [22] [23]

---

[22] A violation of a Reliability Standard is non-public until it is filed with FERC, at which point any confidential Information, including privileged and critical energy infrastructure information, has been removed and the violation is made available to the public by FERC.

Figure 27 reveals that from 2011 to 2012, 82 percent of O&P and 83 percent of CIP violations were self-reported or self-certified by Registered Entities.

Figure 27: Reliability Standard Violations: Discovery Methods, 2011-2012

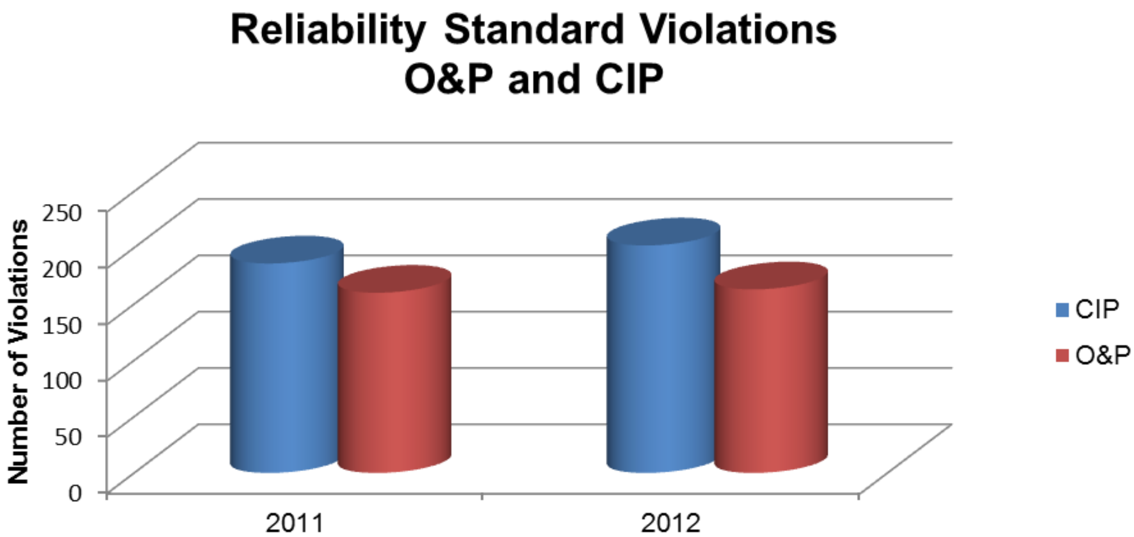


In both instances, the data reflects that Registered Entities in the Western Interconnection are taking a proactive approach at adhering to the standards and not waiting for an external party to uncover violations of the standards. This is beneficial because the longer some violations continue, greater the risk to reliability in the system.

Figure 28 illustrates the number of violations per O&P and CIP categories. Since 2011, the number of the violations has stabilized, allowing for a detailed analysis of which standards are being violated more frequently and how they add to the risk to reliability in the system.

[23] A Validated violation of a Reliability Standard is a violation that has been processed or is being processed through to final disposition by WECC staff. Validated violations are different from 'closed' violations, which have been processed and have received final approval by FERC

Figure 28: Reliability Standard Violations, O&P and CIP



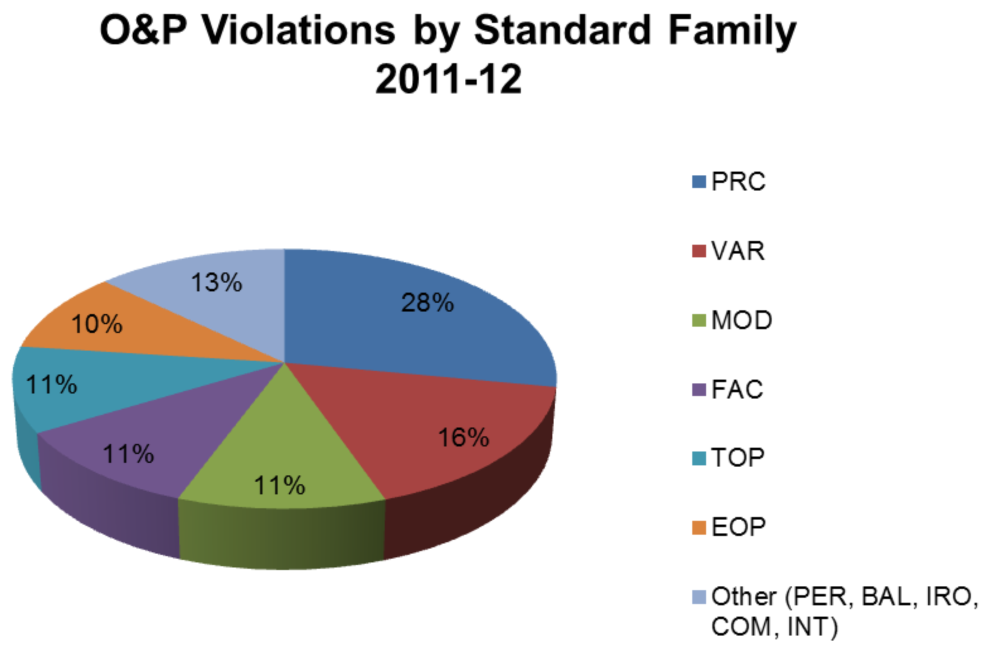
There are 12 standard 'families' categorized under O&P. Each individual family has numerous standards and requirements. A full description of each standard can be found on the NERC website.[24] The standard families include:

1. Resource and Demand Balancing (BAL)
2. Communications (COM)
3. Emergency Preparedness and Operations (EOP)
4. Facilities Design, connections, and Maintenance (FAC)
5. Interchange Scheduling and Coordination (INT)
6. Interconnection Reliability Operations and Coordination (IRO)
7. Modeling, Data, and Analysis (MOD)
8. Personal Performance, Training, and Qualifications (PER)
9. Protection and Control (PRC)
10. Transmission Operations (TOP)
11. Transmission Planning (TPL)
12. Voltage and Reactive (VAR)

Figure 29 reveals the breakdown by standard family of the 323 O&P violations that have occurred in 2011 and 2012.

[24] Reliability Standards: http://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx

Figure 29: O&P Violations by Standard Family, 2011-2012



The largest number of violations occurred in the PRC, VAR, MOD, FAC and TOP family of standards. The PRC standards require the installation and proper maintenance and testing of protection systems in the Western Interconnection. As discussed in the Protection System Misoperation section, these systems can mitigate the impact of events if they are working appropriately.

The VAR standards require proper operation controls of generating resources. If the resources are operated outside of the applicable facility ratings, or what they were designed to do, voltage regulators can protect the system against damage. If a voltage regulator is not working properly or is not being used, the risk to reliability of the Bulk Electric System is increased and major components of the system can be damaged.

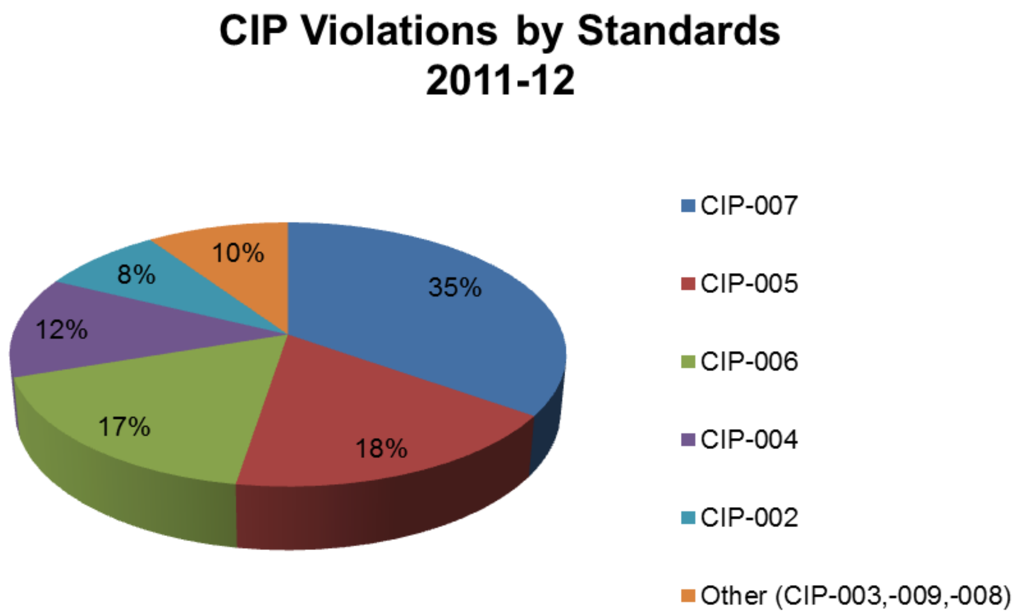
The MOD standards encompass proper modeling of future states of the system. Each operator, either transmission or generation when requested, is required to provide operating characteristics for their part of the system. This allows the Regional Entities the ability to compile an overall system model for future planning. Failure to properly provide data to be included in a range of future scenarios can lead to incorrect assumptions of the future state of the Western Interconnection and an increase in the risk to reliability.

The FAC standards require the proper establishment of a facilities rating to assist in the planning of SOLs and the connection and performance requirements to avoid adverse impacts to reliability. Analysis of the Facility Rating metric data is planned for the 2013 State of the Interconnection report.

The TOP standards are directed at how each operator of a portion of the transmission system operates. If a transmission line is operated outside of the IROL or the SOL other transmission lines will be impacted. Not adhering to the limits will increase the risk to reliability and add to the possibility of an outage that can cascade across multiple portions of the Western Interconnection. In future State of the Interconnection reports, further analysis into the frequency of IROL and SOL violations by mile of transmission system will be analyzed for further recommendations.

The second standard category, CIP, is a single family of standards. Figure 30 is the breakdown of the 388 violations that have occurred in 2011 and 2012.

Figure 30: CIP Violations by Standards, 2011-2012



The top three standards accounting for a majority of the violations are CIP-007, CIP-005 and CIP-006. CIP-005 and -006 deal with how to protect critical infrastructure by controlling physical access through electronic security perimeters, while CIP-007 deals with the proper protection of Critical Cyber Assets. In terms of reliability, these standards are meant to prevent outages due to human interference, such as sabotage. Without proper training on how to prevent unauthorized access, the risk to reliability will increase and a human interference outage could occur.

Summary and Recommendations

In the 2011-2012 timeframe, the number of violations in both the O&P and CIP categories has stabilized in the Western Interconnection. Looking into each of the standards and understanding how they influence the risk to reliability can reveal either a need for better training, stronger security systems, better operating practices, or even more communication. Although the standards are numerous and all should be analyzed on a regular basis, future State of the Interconnection reports should continue to focus on analyzing the most violated standards.

In addition, continued effort is underway to correlate Reliability Standard violations to the WECC Outage Cause Categories used in TADS and the WECC Event Analysis Cause Categories used in Event Analysis. Once completed, an analysis of how standards violations can impact the risk to reliability will be feasible.

Finally, further analysis will be conducted on SOL and IROL exceedances and Facility Path Ratings. These individual studies will be incorporated with the future analysis done on violated Reliability Standards.

Conclusion

The objective of the State of the Interconnection report is to develop reasonable measurements that verify reliability trends. The 2011 and 2012 reports have laid the framework to conduct future analysis for this objective. WECC encourages industry participants to review the report and incorporate the analysis in their own generation and/or transmission portfolios. By comparing the State of the Interconnection report findings with the industry participant's independent results, entities may be able to determine where improvements to reliability can be made within their own organizations.