BONNEVILLE/WESTERN U.S. POWER OUTAGE

OVERSIGHT HEARING

BEFORE THE

SUBCOMMITTEE ON WATER AND POWER RESOURCES

OF THE

COMMITTEE ON RESOURCES HOUSE OF REPRESENTATIVES

ONE HUNDRED FOURTH CONGRESS

SECOND SESSION

ON

ISSUES AND RECOMMENDATIONS CONCERNING THE AUGUST 10, 1996, BONNEVILLE/WESTERN U.S. POWER OUTAGE

NOVEMBER 7, 1996—LOS ANGELES, CA

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BONNEVILLE/WESTERN U.S. POWER OUTAGE OF AUGUST 10, 1996

THURSDAY, NOVEMBER 7, 1996

U.S. HOUSE OF REPRESENTATIVES,
SUBCOMMITTEE ON WATER AND POWER RESOURCES,
COMMITTEE ON RESOURCES,
Los Angeles, CA.

The Subcommittee met, pursuant to call, at 10:08 a.m., in the 15th floor Boardroom, Los Angeles Department of Water and Power, 111 North Hope Street, Los Angeles, California, Hon. John T. Doolittle (Chairman of the Subcommittee) presiding.

Mr. DOOLITTLE. The Subcommittee on Water and Power Resources will come to order. We are meeting today to hear testimony regarding issues and recommendations concerning the August 10, 1996, Bonneville Western U.S. power outage.

Before I go any further, I am very pleased to introduce the president of the Los Angeles City Council and our host, Mr. John Ferraro, for comments that he would care to offer.

Mr. FERRARO. Mr. Chairman, first of all, congratulations on your victory 2 days ago, and welcome back to Los Angeles.

Mr. DOOLITTLE. Thank you.

STATEMENT OF JOHN FERRARO, PRESIDENT OF LOS ANGELES CITY COUNCIL

Mr. FERRARO. I know you have lived in Los Angeles in the past. We had another famous Doolittle in Los Angeles, the general.

On behalf of the city council and the mayor, Mayor Riordan, I would like to welcome you to the City of Los Angeles. We are honored that you have selected Los Angeles as the location for the first congressional hearing regarding the power outage of August 10th. In my more than 30 years on the city council, I have had an opportunity to closely monitor the activities of our electric utility, the Los Angeles Department of Water and Power, and I long have been impressed by the reliability of service the DWP provides to the people of Los Angeles.

The three-and-a-half million people who live in the City of Los Angeles are like most people everywhere. They really do not think about electric service until they lose it, as they did on August 10th.

We in Los Angeles felt very fortunate when our Department of Water and Power was able to restore the service completely within 2 hours. And I have been told that our quick recovery enabled us to assist other utilities in bringing up their systems. That speaks well for our Department of Water and Power.

The August outage, as well as the one in July, highlighted the need for reliability in the interconnected transmission system and for the need of prompt exchange of information between utilities.

You are to be commended for holding this hearing. We appreciate your inquiry and look forward to any light that you can shed on how future outages of this magnitude can be avoided.

Your presence here demonstrates the importance you place on the reliability of electric service for the people of our country. The mayor and the city council of Los Angeles greatly appreciate your efforts in this regard and want you to know that our city is at your service, ready to assist you in any way we can.

Again, welcome to Los Angeles. We are happy to have you here, and we wish you every success in this important effort.

Mr. DOOLITTLE. Well, thank you very much for your kind remarks, and we are grateful to you and the city and the Department of Water and Power for making available the hearing room today and providing us with all the attendant services.

STATEMENT OF THE HON. JOHN T. DOOLITTLE, A U.S. REPRESENTATIVE FROM CALIFORNIA, CHAIRMAN, SUBCOMMITTEE ON WATER AND POWER RESOURCES

Mr. DOOLITTLE. Beginning at about 3:45 p.m. PDT on Saturday, August 10, 1996, the interstate power grid disappeared for approximately 7.5 million customers in the Western United States and Canada. People, businesses, governments, even the operators of the electric generating stations themselves were without power for periods ranging from several minutes to about 9 hours.

The outage was triggered by the loss of transmission lines in the Portland area, which was due to the failure by the Bonneville Power Administration to keep trees trimmed in its transmission right-of-way areas. The lines came in contact with the trees and shorted out.

Although BPA's failure to keep trees trimmed initiated the chain reaction that caused the system to fail, I believe it will be clear from this hearing that many other factors contributed to the outage. A small percentage of those factors were acts of nature, but most were the result of the exercise of human judgment.

In addition to interrupting service to customers that day, the outage also resulted in the automatic shutdown of 15 large thermal and nuclear generating units in California and the southwest. I do not think most of the public realized that this secondary consequence put the entire Western grid in a compromised condition for several days.

A few of those large units did not return to service until the following Tuesday or Wednesday of that week, requiring the purchase of emergency power during that period.

The purpose of this hearing is to address the following questions:

1. What did occur on August 10, 1996?
2. Why did it occur?
3. What steps should be taken by the Federal agencies that caused the outage to change their policies, procedures, and equipment to make sure that the events are not repeated?
4. What legislative action, if any, may be required?

I would like to take a minute to provide some background on several issues. The Bonneville Power Administration, a part of the Department of Energy, was created by the Federal Government in 1937 to market power from Federal hydropower projects in the Pacific Northwest.

Since then, the Federal Government has played a dominant role in Northwest power markets through the operations of Bonneville. Bonneville has control over 80 percent of the region's high voltage transmission. Historically, Bonneville has had a good record of maintaining its transmission service.

Although Bonneville sells most of the Federal power in the Pacific Northwest, it provides a significant amount of power directly to California during the summer months. In addition, Bonneville transmits power from other Northwest utility companies to California over its lines.

As a result, there are heavy power flows from the Pacific Northwest to California and the Southwest in the summer. In the winter, the power flows north to heat the Pacific Northwest.

In response to this outage, the Western Systems Coordinating Council, the entity which currently has the responsibility to evaluate these events, conducted an investigation and released a report on October 18, 1996, describing the causes of the outage and recommending solutions.

The WSCC report on the August 10th outage raises many technical questions about the way in which Bonneville operates its hydroelectric and transmission facilities. However, some of the larger issues in this case concern Bonneville's and the Federal Government's overall ability to realize when there is a problem, the Federal Government's ability to manage these assets and the relative consequences of Federal action or inaction compared with the rest of the electric utility industry.

Several transmission line flashovers and equipment problems contributed to the August 10th outage. Perhaps none of these incidents would, in isolation, have resulted in an outage, but taken together their cumulative effect was to put the entire system in a precarious state. Western concluded that Bonneville was not in fact operating in accordance with Western's minimum standards.

There is a lot of talk in this case of unexpected contingencies and the low probability of all of these events occurring at one time. I believe this discussion misses the point. The question is whether there is an ongoing awareness of the state of the system so that as events and decisions are made operators are conscious of the factors which are pushing the system closer and closer to failure.

Although three 500-kv lines were lost in the hour and a half prior to the outage, though such flashovers indeed had caused similar problems in the region a month earlier and though Bonneville had realized that there was reduced backup capability based on planned and unplanned maintenance outages as well as units out of service for fish flows, it seems that Bonneville did not understand the implications of the transmission lines systematically failing one after another on the afternoon of August 10th and did not take the necessary steps to mitigate the impact on the system.

I believe it is our responsibility to look at these risks, not just in terms of the isolated technical events but in terms of the bigger picture and our need to be aware of the factors that are pushing the system beyond its capability.

We will also look at the role played by individual operating decisions leading up to the events like this one, decisions such as when maintenance is scheduled and when units are off-line or at reduced capacity for fish recovery operations.

More importantly, we want to look at whether we retain the flexibility to modify those decisions if a decision that was good 6 months or a year ago no longer makes sense in light of rapidly evolving crises.

I look forward to hearing from the witnesses and determining what steps need to be taken to ensure that the Federal agencies play a responsible role in ensuring a reliable electric supply system.

I might mention that we had other members scheduled to attend today and one has a very ill mother and elected to remain near her side and just with the rush of events following the elections made it difficult for some to make it.

Our ranking member, Mr. DeFazio, has submitted a statement for the record which will be incorporated in the hearing transcript.

[The prepared statement of Hon. Peter DeFazio follows:]

PREPARED STATEMENT OF HON. PETER DEFAZIO, A U.S. REPRESENTATIVE FROM OREGON

Mr. Chairman, this hearing has been called to investigate the issues associated with the electric power outage of August 10, 1996. This outage, which was the second major outage of the summer, has given consumers reason to wonder whether the lights will come on when they hit the switch. I am deeply concerned that this outage, and the previous outages of July 2 and July 3, may be indicative of underlying problems in the electric power system. Because it is the basic reliability of the system that ought to be our fundamental concern, I am disappointed that the Chairman has limited this hearing to the August 10 outage. If we want to determine causes of past outages and identify remedies to those causes, we shouldn't let politics limit the scope of our analysis.

The preliminary report from the Western Systems Coordinating Council (WSCC) provides a number of conclusions and recommendations regarding the August 10 outage. The report faults the Bonneville Power Administration and Army Corps of Engineers, among others. I am anxious to hear what steps BPA and the Corps are taking to respond to these findings. The public has every reason to expect that our Federal agencies will effectively manage the resources under their jurisdiction.

I would also note that the WSCC report makes recommendations for actions that Southwest utilities—and California utilities, in particular—can take to protect California and Southwest consumers from another intertie separation. It does seem surprising that as a result of a loss of 7,000 MW from the Northwest, more than 27,000 MW of generation went off-line in California. I am anxious to hear from non-Northwest utilities what actions they intend to take to implement these recommendations. It would be unreasonable to expect Northwest ratepayers to pay for system enhancements that aid California responsibility. To put that another way; while we in the Northwest are putting our house in order, we do not wish to have rocks thrown from the glass house across the street.

Mr. DOOLITTLE. I would like to invite our first panel of witnesses to come forward please, if Mr. Bonsall will come up and Mr. Hardy and Mr. Velehradsky, they will be our first panel.

And if you gentlemen would remain standing and raise your right hand, we will administer the oath here.

[Witnesses sworn.]

Mr. DOOLITTLE. Let the record reflect each answered in the affirmative.

Please be seated.

Mr. Bonsall is Chairman of the Western Systems Coordinating Council. Mr. Hardy is the Administrator of the Bonneville Power Administration. Mr. Velehradsky is the Director of Engineering and Technical Services, North Pacific Division, U.S. Army Corps of Engineers.

My counsel has reminded me that we have given Mr. Bonsall some extra time, but I guess in view of the fact that we are it, time will not be such a factor, so while the lights will be there for your guidance, I feel comfortable in telling you if you wish to go beyond that, please feel free to do so.

Mr. Bonsall, will you please begin with your testimony?

STATEMENT OF MARK B. BONSALL, CHAIRMAN, WESTERN SYSTEMS COORDINATING COUNCIL

Mr. BONSALL. Thank you, Chairman Doolittle. It is a pleasure to appear before you today to discuss the August 10, 1996, power outage that affected the Western United States, Western Canada and Northern Mexico and the actions taken following the outage and the conclusions and recommendations that have been developed as a result of the outage.

I am Mark Bonsall. I am Chairman of the Western Systems Coordinating Council and Associate General Manager for Marketing, Customer Service, Finance and Planning at the Salt River Project in Phoenix, Arizona.

WSCC is the largest and most diverse of the ten regional reliability councils of the North American Electric Reliability Council, or NERC. WSCC's service territory extends from Canada to Mexico, an area of nearly 1.8 million square miles. It includes the provinces of Alberta and British Columbia, the northern portion of Baja, California, Mexico and all or portions of the 14 Western states in between.

Due to the vastness and diverse characteristics of the region, WSCC's members face unique challenges in coordinating the day-to-day operation and long-range planning required to provide reliable and affordable electric service to the more than 59 million people within the WSCC region.

The interconnected transmission system within the WSCC region is known as the Western Interconnection. It is one of the five major electric system networks in NERC.

At 3:48 p.m. Pacific Advanced Standard Time on Saturday, August 10th, a major power outage occurred on the Western Interconnection, interrupting service to seven and a half million customers for periods ranging from several minutes to about 9 hours.

In the hours before the power outage, three lightly loaded 500,000-volt or kv, 500 kv lines, Big Eddy-Ostrander, John Day-Marion and Marion-Lane, in the Portland area were forced out of service. These 500 kv lines were providing voltage support for the transmission system. Two of the line outages were caused by flashovers or short circuits to trees. A third line was forced out of service because a circuit breaker was out of service when the second line outage occurred.

While none of these line outages were individually judged to be crucial by Bonneville Power Administration dispatchers, the cumulative impact resulted in a weaker system.

Voltages were adjusted, but no schedules were reduced. In addition, two 115 kv transmission lines, two 500-volt circuit breakers and a 500,000/230,000-volt transformer, all in the Portland area, were out of service for modifications and/or repairs. These outages contributed to the system stress following the subsequent loss of the Keeler-Allston 500 kv line.

The power outage effectively began when the heavily loaded Keeler-Allston 500 kv line, which is in the Portland, Oregon area, sagged too close to a tree and flashed over. Loss of the Keeler-Allston 500 kv line precipitated the overloading and tripping of two underlying parallel transmission lines in the Portland area, one due to a flashover to a tree and one due to a relay malfunction, which depressed the surrounding transmission system voltages.

The depressed voltages led to the subsequent tripping of hydroelectric generating units at the McNary Dam due to excitation equipment problems.

This combination of events triggered increasing voltage oscillations on the interconnected transmission system, eventually causing protective devices to trip the three 500 kv California-Oregon Intertie lines, three of the four major transmission lines that tie the Pacific Northwest to California.

The outage of these three lines resulted in transmission and generation outages that culminated in the system separating into four islands.

System islanding is used in the West as a safety net to prevent a total blackout, minimize the number of customers affected and minimize the time required to restore customer service. Because islanding did not occur in a fully controlled manner, loss of the California-Oregon Intertie resulted in the loss of approximately 21,400 megawatts of generation and approximately 27,400 megawatts of under frequency load shedding, over seven million customers in northern California and the southwest.

The interconnected transmission system from Canada south through Washington and Oregon to California was heavily loaded because of high temperatures near or above 100 degrees throughout much of the WSCC region. In addition, because of the excellent hydroelectric conditions in Canada and the Northwest, the amount of power being transferred including large economy transfers from Canada into the Northwest and from the Northwest to California was high but within established transfer capability limits.

In the wake of this outage, an emergency meeting of senior management from Western utilities, the United States Department of Energy and the State regulatory community was convened on August 12th. A lower power flow transfer limit from 4800 megawatts to 3200 megawatts was established for the California-Oregon Intertie until additional studies had been conducted and the results approved by a newly established WSCC operating capability policy committee.

In addition, Bonneville Power Administration began a comprehensive study to assess the voltage support capability of its system. BPA also agreed to report all outages of 500 kv transmission lines and other key facilities on its system.

In conjunction with the U.S. Army Corps of Engineers, BPA also initiated a review to understand the loss of the McNary generators and to prevent their loss in the event of a future disturbance.

Changes have been made to the McNary excitation systems. As an additional precaution, the Northeast/Southeast Separation Scheme was placed back in service. Additionally, all WSCC members have been asked to review their tree trimming programs, their system's voltage support capability and the NERC recommendations set forth in the publication entitled "Survey of the Voltage Collapse Phenomenon."

As is standard practice for WSCC and its members following a system-wide power outage, a task force of industry experts conducted a thorough review of the power outage and recommended actions to lessen the potential for the occurrence of a similar event in the future.

As part of the standard outage analysis and review process, WSCC policies, procedures and monitoring activities are being reviewed as well to identify any necessary improvements.

The final report on the August 10th outage includes 32 conclusions and over 90 associated recommendations. All recommendations are logged and tracked until they are completed. The report has been submitted to the U.S. Department of Energy and the North American Electric Reliability Council.

In reviewing the August 10th outage, the task force identified four key findings: the interconnected transmission system was unknowingly being operated in violation of WSCC reliability criteria; transmission line right-of-way maintenance, operating studies and system operating instructions to dispatchers were inadequate; contingency plans should have been adopted to mitigate the effects of an outage of the Keeler-Allston 500 kv transmission line; and, last, the loss of the 13 McNary hydroelectric generating units in the Northwest was a major factor leading to the outage of the three 500 kv California-Oregon Intertie lines and the subsequent islanding of the WSCC interconnected system.

This power outage indicates the need to identify and implement strategies that will minimize the potential for more severe unforeseen events and should such events occur minimize the impact of the outages. It also highlights the need for continued vigilance to reasonably ensure that all equipment will operate as expected.

WSCC and the other regional councils are in the process of implementing additional security process measures. These measures will enhance interconnected system reliability through the exchange of information required to augment system security and reliability, including on-line power flow and security analysis and increased system monitoring.

These measures will enhance the operators' ability to identify potential problem outages and take corrective actions. Within the WSCC region, there will be four security coordinators responsible for the active monitoring of electric system conditions on a real-time basis to proactively anticipate and mitigate potential problems and coordinate restoration following a system emergency.

In addition, to safeguard the reliability of interconnected electric system operation, numerous technical studies are conducted each year to reasonably ensure that critical operating conditions are thoroughly examined and evaluated. These studies include assessments of low probability events that are expected to result in system islanding and under frequency load shedding.

Islanding and under frequency load shedding are protective actions used in the West for severe low probability disturbances to stabilize the system, minimize customer interruptions and allow rapid system restoration.

Additional studies are being conducted to ensure a broad range of operating conditions have been adequately studied and that the system is being operated in compliance with WSCC and NERC criteria and policies.

WSCC members are looking at a wide variety of conditions and contingencies to ensure that the system is planned and operated within established WSCC reliability criteria.

In all likelihood, the August 10th power outage could have been avoided if contingency plans had been adopted to minimize the effects of an outage of the Keeler-Allston 500 kv line in the Pacific Northwest.

In addition, the task force determined that the loss of the McNary generating units and inadequate tree trimming practices, operating studies and instructions to dispatchers did play a significant role in the severity of the disturbance.

As the electric industry becomes more competitive, we must make certain that interconnected system reliability is preserved. We must ensure that all entities that own, operate or use the interconnected transmission system are complying with the established criteria, guidelines, policies and procedures of WSCC and NERC.

I believe there are three essential steps that must be taken to ensure system reliability in an era of competition:

1. Mandatory compliance with established standards;
2. Mandatory membership in the regional reliability councils and NERC; and
3. Expanded compliance monitoring with appropriate incentives, sanctions or fines.

As the industry is restructured and competition increases, it will become even more important for all market participants to adhere to the rules of the road, especially since fewer participants, if any, will be willing to go the extra mile and incur the added expense to meet a competitor's obligation for ensuring reliability. It is for this reason that the industry widely shares the view that voluntary compliance will no longer be adequate.

And if I might expedite the completion of my comments, I would like to add a couple of comments in addition to those submitted for the record.

Mr. Chairman, it is obviously in no one's best interest in this industry that events of this magnitude, either the July 2nd or the August 10th event, take place. I would like to thank the members of the task force that completed the disturbance report for the WSCC for their, I think, timely and exhaustive efforts to compile the disturbance report and accumulate the recommendations therein.

I would also like to recognize the two organizations that are the subject of those reports, Idaho Power Company and Bonneville Power Administration, as having fine reliability records over all and I would like to thank BPA in particular for its aggressive cooperation and pursuit of the root causes of the August 10th outage.

Unfortunately, both of these organizations encountered fairly unique conditions and, as a result, the incidents did take place. From WSCC's point of view, these incidents are absolutely unacceptable and we will do everything in our power to prevent their recurrence.

If there are two facts I would point out as a result of these occurrences, the first is that as we consider the deregulation of the electric utility industry as a matter of economic structure and conduct and performance, it is entirely possible to consider or segment the industry into generation, transmission and distribution components. As a matter of reliability, it is not. The components operate conjunctively to preserve reliability and we need to keep that fact in mind as we address otherwise restructuring the industry in a deregulated environment.

Secondly, the reliability councils that are in place throughout the United States in at least one way represent the cumulative reliability intelligence of this nation and I think they are good institutions and as we address the issue of how to preserve reliability in a deregulated environment, I would encourage your consideration of the continued or extended use of the existing reliability councils.

Thank you, Mr. Chairman, and I am happy to accept any questions you may have.

[The prepared statement of Mr. Bonsall may be found at the end of the hearing.]

[Western System Coordinating Council Report may be found at the end of hearing.]

Mr. DOOLITTLE. Thank you.

What we will do is hear from the other witnesses on the panel, and then I will ask questions of all three of you.

Mr. Hardy, you are recognized for your testimony.

STATEMENT OF RANDALL HARDY, ADMINISTRATOR, BONNEVILLE POWER ADMINISTRATION, U.S. DEPARTMENT OF ENERGY

Mr. HARDY. Thank you, Mr. Chairman. I am Randall Hardy, the Administrator and Chief Executive Officer of the Bonneville Power Administration.

I would like to start this morning by talking a little bit about the benefits the intertie has provided, Bonneville's reliability record, then discuss the specifics of the events and, more specifically, what Bonneville and the Corps are doing to make sure this does not happen again.

The Pacific Northwest/Southwest Intertie has a total transfer capability of some 7900 megawatts. Mr. Chairman, you pointed out in your statement, it takes advantage of the seasonal diversity between the Northwest and the southwest to maximize the economic benefits for both regions.

California consumers have benefited to the tune of roughly $1 million a day for the last 30 years as a result of the interties being in place. The interties have also led to significant reductions in pollution, particularly in the L.A. basin during critical times of the year.

BPA has a good, and I would say excellent, reliability record historically. That being said, we are severely chastened by the events of August 10th in particular and accept full responsibility for our part in those events, which was considerable.

As regards our reliability record, a recent WSCC audit has found us to have a well operated system that consistently operates in conformance with WSCC reliability criteria and even in spite of the August 10th outage, we made the NERC honor roll this year with a 96.8 percent compliance capability with NERC standards.

I think Mark has described fairly accurately the events on August 10th. Let me just offer an observation in a more general sense. This was produced by a combination of inadequate tree trimming, and failure to anticipate a combination of high hydro runoff and high load conditions that in retrospect exposed our system to some voltage support vulnerabilities that we did not fully understand.

This was the highest hydro year we had in 20 years. Normally, the runoff ends around June 30th and hence you have lower loadings in July and August, the peak load times in California. This year, the runoff went all the way through August, and that created some vulnerabilities that we had not fully understood and which we are now working to understand and to correct.

Finally, we had events surrounding McNary where we lost 13 units in 73 seconds, really an unprecedented kind of circumstance relative to a major hydro facility. We are working with the Corps to actively try to correct that problem and make sure that we do not have similar problems at other hydroelectric facilities.

Let me focus now on the specific things that Bonneville is doing to try to ensure that a repeat of this action will not occur.

First, as Mark mentioned, in conjunction with the other WSCC parties, we have restricted transfer capability over the AC intertie to 3200 megawatts. Its design capability is 4800 megawatts.

Secondly, we have completed a complete review of our vegetation management program with Bonneville, entailing some 46 recommendations and we intend to implement all of them. Significant among those recommendations are, first, a variety of management actions to clarify responsibilities in the tree trimming area. These involve both who is responsible for what, actions and better defining what constitutes danger brush versus just high brush. If you have a danger brush circumstance, action has to be taken with 24 hours to clear that brush.

Secondly, we have increased our tree trimming budget on the order of 50 percent for the next 3 years. We had in fact increased it last year and the year before from $2.5 million to $3 million but in retrospect that clearly was inadequate to cope with the magnitude of tree growth that we had, particularly growth brought on by the high hydro conditions of the last year.

And, finally, we will go back to the selective use of herbicides and right-of-way management control. We discontinued all but spot herbicide use for right-of-way management in 1984 for environmental reasons. We now have to go back to some more selective use of herbicides to control some of the brush rather than relying strictly on hand cutting. We think we can use herbicides in an environmentally responsible way, but that is an important part of being able to comprehensively address this reliability issue.

The third major action is we have initiated, as Mark referenced, a comprehensive review of the adequacy of voltage support in the Bonneville system. This review is now underway. We have a panel of nationwide and, in some cases, international experts to review those results and suggest other studies that we need to do. They include representatives of the California utilities, from NERC, from WSCC as well as East Coast utilities and other reliability experts from around the country.

I expect that this voltage support review which should be done around the first of the year will produce conclusions in three areas.

First, it will clearly show where we need to add additional system reactive capability on the Bonneville system. This will not be cheap. I anticipate that it will cost somewhere between 10 and 50 million dollars to install the appropriate reactive capacity at key points in the system to fix these vulnerability problems.

Secondly, it will focus on getting better availability of Corps generation at key plants in the lower Snake and lower Columbia.

And, third, I think it will address the fish problems and the kind of reliability consequences of the fish operation that we have been running in the Northwest for the last 2 to 3 years, consequences which we had not fully appreciated prior to the August 10th outage.

The fourth major action addresses communication problems we had with other utilities in the August 10th outage. We have now an operating agreement with Pacific Gas and with Southern Cal Edison which I expect will be expanded to all the intertie owners over the next few weeks where we have identified specific so-called key facilities, quote-unquote, where if we have a problem, we will notify each other that there is a problem or there is an outage.

Prior to this time, the definition of key facilities was the criteria used in WSCC reliability criteria but that was at the discretion of the owning utility. We have essentially taken an action with all three utilities to remove the element of discretion from dispatchers and simply specify what facilities, if there is an outage, will be reported to the other intertie owners and participants.

Secondly, a key part of this operating agreement is a change in the paradigm that our dispatchers jointly used up to this point. Prior to August 10, if we had something looked like it might be a problem on the system, our tendency was to not cut schedules but to try to resolve the problem first. The paradigm is now cut schedules first, ask questions afterwards.

We will reduce the schedules if there is an apparent problem and then argue about whether there is a problem or not and then restore the schedules once we determine whether there is a problem and, if so, what the fix is. That is a significant change in the operating that all of our dispatchers have used.

Fifth, we are working with the Corps of Engineers. We think we have found the fix to the exciter problem and associated relay problem at McNary and, as I am sure John Velehradsky will describe, we are probably within 30 days, I think, of being able to install the necessary equipment, test it to the satisfaction of all WSCC members and that will enable us to take the AC intertie limitations back up from 3200 to maybe 3600 or a little higher.

Sixth and finally, we have instituted a variety of actions with the Corps of Engineers to try to improve our communication, and data coordination, between the generation and transmission facilities since the Corps is the owner and operator of the generation facilities and we simply are the marketer of the power output from those facilities. We also will ensure that the Corps plants are operated in a way where they are fully cognizant of the various transmission system exposures that they are likely to be subject to.

Those are the major areas of a much more comprehensive set of recommendations that we are implementing. We intend to implement every recommendation that applies to us in the WSCC report and probably go well beyond that, particularly with the results of the voltage support study that we are engaged in now.

I would like to say just a couple of words about the future as distinct from this particular set of circumstances.

Let me make clear at the outset that I do not think that you can legitimately attribute this outage to any factors involved with deregulation. That being said, it is clear that we have major challenges ahead of us in the deregulation area to ensure we make this transition to a fully competitive marketplace, at least at wholesale and possibly at retail, in ways that do not impact system reliability.

I would like to suggest three things that pretty much parallel what Mark said and what I expect you will hear from Pacific Gas and Edison as well.

First, we need mandatory membership in reliability councils and in NERC. We cannot have a load control area operator that can opt out of membership in a reliability council structure as they can now.

Second, we need mandatory compliance with NERC and WSCC recommendations. You cannot have the option to opt out if that is necessary to maintain system reliability.

Third, we need strong independent system operators. The industry is moving toward the ISO/IGO concept, but it is imperative that the system operator have both the scheduling responsibility and the dispatch responsibility under his control. If we allow those two things to be separated, we are asking for significant problems as we move into the deregulated marketplace.

Mr. Chairman, that concludes my statement. I would be happy to answer any questions at your discretion.

[The prepared statement of Mr. Randall Hardy may be found at the end of the hearing.]

Mr. DOOLITTLE. Thank you very much.

Mr. Velehradsky, you are recognized.

STATEMENT OF JOHN E. VELEHRADSKY, DIRECTOR, ENGINEERING AND TECHNICAL SERVICES, NORTH PACIFIC DIVISION, U.S. ARMY CORPS OF ENGINEERS

Mr. VELEHRADSKY. Mr. Chairman, I am John Velehradsky, Director of Engineering and Technical Services, North Pacific Division, U.S. Army Corps of Engineers. I am pleased to be here today representing Mr. Martin Lancaster, the Assistant Secretary of Army for Civil Works.

I am responsible for the technical direction of the planning, design, construction, operations, readiness and real estate activities associated with the Corps of Engineers' water resources management activities in the Columbia River basin. In my testimony, I will briefly describe the Corps' hydroelectric generation facilities in the Northwest and how they are managed. I will address the outage of August 10, 1996, as it relates to the Corps' operation and management. I will also explain the actions that the Corps has taken since the incident to help this multi-jurisdictional power system respond to such abnormal occurrences.

The Corps of Engineers operates and maintains 21 hydroelectric projects in the Western Systems Coordinating Council service area. The maximum generation capacity at the 21 Corps dams is 12,937 megawatts, which represents approximately 24.5 percent of the hydro power capacity of the Northwest.

One of these 21 Corps projects is at McNary Dam, located about 292 miles upstream from the mouth of the Columbia River and near Umatilla, Oregon. As a result of the voltage depression in the system on August 10th, the generators at McNary tripped off in order to protect the equipment.

Power generated at the Corps projects is marketed and transmitted to customers by another Federal agency, the Bonneville Power Administration. Many factors affect how these dams and reservoirs are managed to produce power. The Columbia River Treaty regulates how water and power are traded between the United States and Canada, and the Pacific Northwest Coordination Agreement specifies how power is produced and shared among regional utilities.

There are also many non-power uses for the Columbia River that affect how Corps facilities are operated. The dams and reservoirs that the Corps operates are multi-purpose projects that balance the demand for hydro power with other legitimate uses for the water, including navigation, flood control, water supply, recreation and fish passage. All these factors are considered in the development of operation plans for the reservoirs in the Columbia River system.

The Columbia River and its tributaries are home to salmon and sturgeon that annually migrate the rivers moving past these series of dams that have been constructed in their path. During critical fish passage periods from April through August, water control and hydro power operations are managed to avoid jeopardy to salmon and sturgeon that are protected under the Endangered Species Act and to mitigate impact to other important fish and wildlife resources.

To facilitate fish migration, extra releases are allowed to bypass the generators at carefully timed intervals. This activity requires close coordination among the Corps' water managers, Bonneville Power Administration's dispatchers and power plant operators.

Following the power disturbance that occurred on August 10, 1996, the WSCC released findings concerning the July 2–3 and August 10, 1996, disturbances. The council's findings as they relate to the Corps operations are paraphrased as follows: the power system experienced depressed transmission system voltage prior to McNary tripping; the McNary generators tripped off sooner than would have been expected based on power system studies; the level of generator voltage support available in the Hanford area was inadequate to prevent system collapse; and the North American Electric Reliability Council recommendations in the report entitled "Survey of Voltage Collapse Phenomena" need to be implemented.

After this incident, the Corps performed its own assessment of the performance of the generation equipment. We found that the McNary units performed as originally commissioned by the manufacturer. During the period of depressed transmission system voltage just prior to the system shutting down, McNary provided voltage support above machine design capacity for about 5 minutes. Eventually, however, this was insufficient to overcome the losses elsewhere in the system and the generators tripped off.

The 13 McNary generating units shut down in a self-protective mode in response to the major voltage depressions that were occurring in the transmission lines. The automatic tripping of the McNary generators is a safety measure that protects the equipment during such abnormal fluctuations in voltage.

While we found that equipment performance was generally consistent with our expectations, we also learned that the power system voltage in the McNary area was depressed far below any level anticipated, placing a higher than expected demand on the McNary units. As a result, the McNary units tripped off sooner than we had expected. We do not know that had the units stayed on line a few minutes longer the ultimate result of the incident would have been any different.

Although the tripping of the McNary units was only one of the problems associated with the outage, we have identified a few improvements we can make that will help us respond if we are faced with a similar event in the future. These measures respond to the WSCC's findings and recommendations and our program for improving the availability of generation and equipment reliability.

We are making some adjustments to the McNary and other units that will improve their response to an impending voltage collapse in the system. We are improving coordination among Bonneville Power Administration, WSCC and the Corps to assure that everyone involved is aware of the capability of Corps equipment in operation.

These measures that the Corps is taking will not by themselves prevent any future incident like the one we just experienced, but they will assure that the Corps' operated and maintained facilities are more responsive to the power system's future requirements. Together with steps that can be taken by other players in this power network, the whole system will be more reliable.

Mr. Chairman, this completes my testimony. I would be happy to respond to questions.

[The prepared statement of Mr. John E. Velehradsky may be found at the end of the hearing.]

Mr. DOOLITTLE. Thank you very much.

Let me try and understand. I have read quite a bit of this material. It takes a great deal of power to keep pushing the voltage through the lines, does it not? Is not that the problem, you were suffering from low voltage once some of these lines had gone down and you were trying to beef them up and that is what the McNary generators were supposed to kick in and do, but they did not? I am just trying to get the big picture here as to what is happening when we lose these huge transmission lines. Can I get one of you to comment on that for me?

Mr. HARDY. I suppose the best analogy is water through a hose, Mr. Chairman. You need both voltage and current to produce power. One is analogous to the amount of water going through the hose and the other is analogous to the spigot that you are using to adjust it. You need to have both to maintain a reliable power system.

The voltage support/voltage collapse phenomenon is frankly one that is relatively new in the power industry that we are all struggling with to understand. Our system as originally designed, places most of our voltage support at the California-Oregon border. That is where most of our major generation is and that is where most of our voltage support was.

As a result of a variety of changes in system operation, not the least of which is the fish spill program that we now have, and to some extent the availability of generation on the Columbia River, our system center has essentially moved north by a couple hundred miles, and the voltage support has not moved with it. We expect one of the results of the blue ribbon panel study will be to identify where we need to add additional voltage support to make sure that when you have other outages, either on lines that were involved on August 10th or other lines that are critical support of the AC intertie system, we will have an adequate voltage support or reactive capability margin to prevent the recurrence of those events

Mr. DOOLITTLE. I guess what intrigues me is that, it seems like the way the system was set up, you were trying to generate more power to make up for the loss of the lines. Alternatively, you talked about the issue of cutting schedules, which I assume means reducing the amount of power that is produced, right?

Mr. HARDY. Right. That is correct.

Mr. DOOLITTLE. So are there two ways that this problem could be dealt with, either produce more power or produce less?

Mr. HARDY. There are a whole variety of ways that it can be dealt with. Let me try to give you some feel for the different dimensions of how one can tackle this.

One is to keep producing the same amount of power but install additional reactive equipment at key points to prevent voltage oscillations. The second is to cut schedules. If you see a problem developing or something you think might be a problem, then you simply reduce the amount of throughput.

That is what we have basically agreed with Pacific Gas and Edison to do as an operating matter to protect the system now and/or to reduce the overall transfer capability of the system to the 3200 megawatts that it is now at.

A third is to increase the amount of generation that is available to support those lines at key locations. For example, after we restricted interior capacity to 3200 megawatts, Pacific Gas had run studies Sunday afternoon with these restrictions intertie then restricted to 3200 megawatts and facing record peak loads coming up that Monday, August 12, they did not know whether they could carry the load, so we were facing a third potential outage.

At that time, we completely curtailed the fish spill program at The Dalles Dam. The Dalles, again, like McNary, is relatively near to the northern terminus of the intertie. That gave us another 800 megawatts worth of generation and enough associated voltage support that we could take the 3200 limit on the intertie and raise it to 3600 megawatts temporarily. We did curtail fish spill at about 8:30 a.m. Monday, and kept that in effect until Thursday, when Diablo Canyon started to come back on line. But that essentially prevented the lights from going out a third time in California. That Action created considerable political controversy within the Northwest, vis-a-vis the endangered fish that were involved, but that is another issue.

But my point here is you can also solve the problem by having a greater amount of generation available at key points as well as installing reactive as well as cutting schedules or taking other operational actions or having a variety of other automatic control schemes. We are really proceeding on all of those fronts, both within the sphere of the WSCC recommendations as well as our own voltage support study and the other recommendations that I described to you in my testimony.

Mr. DOOLITTLE. This issue of The Dalles, I think I read some place that only 16 percent of its power generating capability was being used on August 10th. I guess that the rest was devoted or foregone in order to support the fish flow. Is that according to your understanding?

Mr. VELEHRADSKY. At the time of the outage or the disturbance, we were scheduled to pass 64 percent of the flows to support the fish passage requirements.

Mr. DOOLITTLE. And I guess ultimately at The Dalles, as you said, they went ahead and changed that around, terminated the fish flows and ran it through the generators. Is that what happened on Monday?

Mr. HARDY. That is correct. That is exactly what happened. We declared an emergency. I went to John's boss at the Corps of Engineers and to the regional director of the National Marine Fisheries Service.

We declared an emergency, suspended the spill program which allowed us to take that unit from about 400 megawatts up to about 1200 megawatts of generation which, along with the associated reactive capability, allowed us to take the total transfer capability in the AC system from 3200 to 3600 megawatts, which was the margin that allowed Pacific Gas to meet load.

Mr. DOOLITTLE. How many hours did it take from the time—is it you as the administrator who declares the emergency? Is that the procedure?

Mr. HARDY. It takes a joint kind of declaration among the three of us.

Mr. DOOLITTLE. The three entities?

Mr. HARDY. I would say the key decisionmaking official here is really not either of us, but the head of the National Marine Fisheries Service who has to say that this in fact meets the criteria for an emergency under the biologic opinion in the Endangered Species Act and we were able to get his immediate concurrence and do this.

Mr. DOOLITTLE. And is that the national head of it?

Mr. HARDY. No, just the regional head. So we can handle the problem and did handle the problem in the region. I think one of the issues, Mr. Chairman, that we are going to look at as we do the voltage support study is can we get that down a level further—to the dispatchers—and have a set of criteria that if the system is started to get in extremist, the dispatcher can take an action to suspend the spill program in order to stabilize the system.

We did not have such an approach in place on August 10, nor do we now have such an approach, but this highlighted, I think, the need to develop one in a way that would be satisfactory to the fish interests in the Northwest.

Mr. DOOLITTLE. Now, under that proposal, the dispatcher is an employee of BPA, is that right?

Mr. HARDY. That is correct.

Mr. DOOLITTLE. So how would this work if your proposal took effect? Who would he have to consult with in order to suspend the fish flow, for example?

Mr. HARDY. The idea, again, I am speaking in advance of what is going to require an elaborate amount of consultation and agreement within the Northwest——

Mr. DOOLITTLE. Sure.

Mr. HARDY. [continuing]——but the idea would be that the dispatcher would have the unilateral ability, if he saw the system being in trouble, to call up the Corps plant manager and say curtail the fish spill operation, which can be done in a minute or two. It is a fairly quick operation. But, for example, there was 5 minutes between the time that Keeler-Allston sagged into the trees and we lost McNary.

We clearly knew we had significant problems when Keeler-Allston went into the trees. If we would have had the ability at that time to call up the plant operator at The Dalles and he/she would have been empowered to take that direction from the Bonneville dispatcher, the outage might have been avoided and we might have been able to stabilize there. That is the kind of a system that I think we ought to seriously investigate as one of several mitigative measures that we might be able to take.

Mr. DOOLITTLE. I am just curious. I have recently—in fact, Mr. Bonsall, I had the privilege of touring some of your facilities in Salt River, and we went to Hoover Dam and saw several other major power generating facilities. Is it literally a telephone call that you propose when this happens? Is there some other means? I know the controllers sit there. I think from Glen Canyon they control several dams from that one physical location. Is it a telephone call? Do you have to hope the guy is not on a break? Or is there some electronic communication that would occur?

Mr. HARDY. It depends on which facility you are talking about. Some of them are telephone calls, some of them we have automatic generation. Most of them we, in fact, have automatic generation control equipment. But I think the key here is the Corps plant manager is the guy who has the ultimate responsibility for overriding or complying or not complying. The circumstance relative to the fish spill program that we both faced, the Bonneville dispatcher and the Corps plant operator at The Dalles, was that neither of them were authorized to curtail that fish program, absent going all the way up to my level, and to the regional director of the National Marine Fisheries Service.

That clearly is not going to happen at 3:45 on a Saturday afternoon. And what we have to do is operationalize that at the working level, hopefully to have some agreement where if you meet certain criteria you can do that immediately.

Mr. DOOLITTLE. I have to tell you, considering how big these bureaucracies are and how many of them there are, I am very impressed that you were able to make that happen in time for Monday.

Mr. HARDY. We had about 30 minutes before I think Pacific Gas was going to get in significant problems, but fortunately we had the right people in the right places and we were able to do that.

Mr. DOOLITTLE. The time it takes to make that decision would be a rather extraordinary record for quick action, would it not?

Mr. HARDY. I guess it is relative to your view of how quickly Federal agencies react, Mr. Chairman. We took the action and, like I alluded to before, there was a consequence to taking that action, a week of fairly substantial political controversy within the Northwest context about the appropriateness of that action or other actions.

Mr. DOOLITTLE. It has been my observation that even the remote possibility of such controversy has paralyzed Federal agencies from acting decisively, at least in any situation I am familiar with. I mean, was this an extraordinary occurrence in your mind?

Can anybody think of a recent example where this kind of concerted action, going against the flow, so to speak, has been able to occur?

Mr. HARDY. I have been administrator for 5 years. I cannot think of another comparable set of circumstances, but I was basically the guy that made the decision and to my mind there was no question. We had a bona fide emergency and we had the needs of some legitimately endangered fish pitted against a basic health and safety issue relative to putting the lights out a third time in California and there was not any question relative to that.

And in fairness, even in the Northwest, when you question the fisheries advocates closely, they were not suggesting that was an inappropriate decision. Most of their criticism was focused on could you not then have taken other actions, to mitigate the consequences of curtailing the spill program. A fair question and we probably were not able to act as quickly on that front as we might otherwise have done.

Mr. DOOLITTLE. Let me ask to speculate on this. Assume that you had this new proposal you are talking about in effect that time on August 10th. The dispatcher, I guess, could have sent the word and fired up The Dalles. Do you believe that would have stopped the outage that subsequently occurred?

Mr. HARDY. Hindsight is perfect. I think it certainly could have. I would say it is probable that it would have, but I cannot say with absolute certainty.

Mr. DOOLITTLE. Do either one of you other gentlemen want to comment?

Mr. BONSALL. I think we will have a better idea on that upon the completion of the studies that are currently underway.

Mr. DOOLITTLE. I read that—what are there, three AC 500,000-volt lines in the California-Oregon Intertie and one DC, is that correct?

Mr. HARDY. That is correct. Three AC and one DC. They are in different locations.

Mr. DOOLITTLE. I think the oldest of them is the DC line, is that right? It seems like the newer ones were AC lines. Is that because those are felt to be preferable or maybe they serve different functions. I do not know.

Mr. HARDY. They do serve different functions. The first two built were the two AC lines, then we built the DC and then the third AC line, which is in a separate right-of-way from the first two AC lines. And that was more of a matter of the kind of economics that I described in the opening part of my testimony.

I think we all agreed with the California owners that added capability which took the total transfer capability of the AC system up substantially could allow us to trade additional power back and forth on a seasonal basis to the economic benefit of both Californians and the Northwest.

Mr. DOOLITTLE. Bonneville has about 15,000 miles of high voltage transmission lines, is that right?

Mr. HARDY. That is correct, Mr. Chairman.

Mr. DOOLITTLE. I am just curious. I have often wondered this as we fly around and see these transmission lines out in remote areas. How do you keep all the vegetation away from those?

Mr. HARDY. We have a combination of ground patrols and aerial patrols to try to spot those problems when they occur. Typically we do at least one ground patrol each year and three aerial patrols a year to try to monitor the growth of vegetation in the various right-of-ways on all of those lines.

Mr. DOOLITTLE. And so in 1 year you mean there are people physically out there on the ground over those 15,000 miles?

Mr. HARDY. Yes, sir.

Mr. DOOLITTLE. How many people are devoted to this purpose?

Mr. HARDY. We have a total of about 1,600 people in our total transmission organization. My guess is you have a total of maybe a couple hundred that are basically the line crew people conduct, patrols along with a variety of other maintenance functions on that 15,000 miles of line. So you are not just looking for brush clearance, you are looking for shot out insulators, you are looking for a variety of other equipment problems.

I used to be an area manager for the Puget Sound area 15 years ago at Bonneville and you regularly fly all of those lines looking for a variety of problems. One of them is vegetation management, but you have a number of other things, particularly damaged insulators, that you are looking for, which could be equally problematic in causing an outage if you are not careful and attentive to replacing those.

Mr. DOOLITTLE. You can tell from the air whether you have damaged insulators?

Mr. HARDY. Yes, sir. That is the principal means—you can fly the helicopter actually quite close. We take videotapes of most of our flyovers so we can go back and review the tapes. Some of the recommendations that I described, the 46 recommendations in our vegetation management program to do we need to change the type of videotape to get a better picture. We are also going to add a fourth aerial patrol each year focusing just on vegetation management.

One of the problems we discovered we had is when you are asking the observer in the helicopter to look for both damaged insulators, other equipment damage and high brush, you are probably asking him to do too much. So we are going to institute a fourth kind of flyover of the entire system, looking just the amount of brush control combined that action, with the ground reports, and clarification of responsibilities among line crews and the other individuals in the individual maintenance districts, will produce a much more comprehensive approach to vegetation control.

Mr. DOOLITTLE. And how far off the ground are these transmission lines typically? I mean, I guess there is a minimum legal standard, is that right?

Mr. HARDY. I would say typically 40 to 60 feet, sometimes higher than that.

Mr. DOOLITTLE. And when you talk about brush, we would think of that as the trees, right?

Mr. HARDY. Right. You are talking about trees as opposed to brush. Particularly in Western Oregon and Western Washington, given the rainfall that occurs there, an alder or a cottonwood can grow eight to ten feet in a single year.

Mr. DOOLITTLE. So when you control that type of vegetation, do you cut the tree down or do you just scale the tree and cut off the last 15 feet or something?

Mr. HARDY. It varies. Sometimes you cut it all the way down, sometimes you just scale it, as you have described.

One of the other things that we have concluded is that hand cutting, whether you are scaling or whether you are completely cutting the tree down, in fact stimulates tree growth in a variety of ways. Hence, one of the recommendations that I described earlier is going back to hand application of herbicides to selected trees where you can actually kill the tree permanently but yet not spread the herbicide to surrounding areas. And we concluded that probably our virtual cessation of use of herbicides in 1984 created some problems that we did not fully appreciate at the time.

Mr. DOOLITTLE. In 1989, who made the decision or at what level was that decision made to suspend using herbicides?

Mr. HARDY. I am not sure, Mr. Chairman. I would like to answer that for the record, if I could.

[The following was submitted:]

HERBICIDES DISCONTINUANCE

The Bonneville Power Administration (Bonneville) restricted the use of herbicides to spot and stump application and control of noxious weeds on Bonneville's right-of-ways in March of 1984. This decision was made by the senior management official responsible for Operations and Maintenance of the Transmission system at the time.

Mr. DOOLITTLE. OK. But, as far as you know, was that something that was peculiar to Bonneville? It was not something that occurred across the country, was it?

Mr. HARDY. I do not think it was peculiar to us at all. In the 7 years before I took over as Bonneville administrator in 1991, I ran the Seattle municipal utility, which is the sixth or seventh largest municipal utility in the country, and we had done the same thing back in the mid 1980's.

For environmental reasons, we had completely ceased using herbicides and gone to basically handcutting and other forms of vegetation management. And I think there was a trend in the industry to do that as a result of the kind of controversies over 2–4–D and other kinds of herbicides in the early 1980's that had some fairly severe environmental consequences.

Today, you have more environmentally benign herbicides and I think we have a more selective way to go about that.

Mr. DOOLITTLE. As you understand it, and I assume you were not there in 1989 when this decision was made——

Mr. HARDY. No, sir. I was not.

Mr. DOOLITTLE. But was it because of this so-called political controversy that the decision not to use herbicides was made, or was it because there was actually some legal impediment imposed by the environmental laws?

Mr. HARDY. I am not certain, Mr. Chairman. I expect it was more the former than the latter. And not just a political controversy but a genuine concern about responsible management in the right-of-ways and what was the right balance between managing these right-of-ways in an environmentally responsible fashion versus maintaining a reliable power system.

And, like I said, for the two utilities, Bonneville and Seattle City Light, that I have been associated with, both of them made the same decision to completely cease herbicide use and I suspect there are a number of other utilities nationwide that if they did not completely cease, significantly cut back because of the controversies that had resulted in the 1970's and early 1980's over more extensive herbicide use.

Mr. DOOLITTLE. Prior to 1989, was it your understanding that utilities preferred not to let any trees grow underneath the power lines?

Mr. HARDY. No, you let some trees grow but you used a variety of control techniques. The fastest growing trees like alder, were typically where you would use herbicides. For example if an alder is 15 feet tall, you can cut it at the base and 2 years later it is back at 20 feet. That is not a particularly cost effective way to manage your right-of-ways nor, in retrospect, is it the safest way.

Mr. DOOLITTLE. I think I read that since the August 10th outage you have inspected 2000-some miles of your right-of-way and I guess dealt with that. How long will it take you to cover the rest and get it taken care of?

Mr. HARDY. We patrolled and inspected all of the miles of right-of-way that are critical or central to support and protection of the AC intertie system. Throughout the remainder of this fiscal year we are currently in, we will do the rest of it on the normal schedule with the additional helicopter patrol that I described before, but I am pretty confident that we have already patrolled and cut, in an initial phase, all of those right-of-ways that are most critical to the reliable support of the AC intertie system.

Mr. DOOLITTLE. When these lines are heavily loaded, they normally sag, right?

Mr. HARDY. That is correct.

Mr. DOOLITTLE. What is the range of movement anyway on high tension lines?

Mr. HARDY. It is considerable. As I recall, to give you one example, as I recall the WSCC report on the July 2nd outage relative to the Pacific Corp line that was involved in between Idaho and the Bridger Cole plant, there was a sag of something in excess of 40 feet, I think.

And I might say that while this is a matter we are still investigating, we have some number of feet unaccounted for in the formulas and the standards that we have used, which is a function of both ambient temperature and line loading, as to how far the lines sag. And we have basically just adapted industry standards for ours.

On some of the key lines, John Day-Marion and Big Eddy-Ostrander, I have about—what is it, Vickie, five to seven feet? Yes. Five to seven feet that I cannot account for yet. I mean, my formula says the line should not have sagged into the tree and yet it did. Or it got close enough, two, three feet, to flashover.

But before we reach a conclusion here, I have asked our staff to go back and talk to some of the East Coast utilities who have similar problems and try to get a better handle on whether this is a standards problem, or is it that we just did not know something that we should have known or what.

Mr. DOOLITTLE. Now, when it touches the tree, it shorts out the line. What happens to the tree?

Mr. HARDY. The tree gets burned. Sometimes you start a fire. So there are other issues involved as well.

Mr. DOOLITTLE. So if the lines are only 40 feet off the ground and they sag 40 feet, I mean, hopefully those are 60 feet off the ground, but there is a fairly dramatic movement. Much more than I realized.

Mr. HARDY. You have a huge amount of movement that can occur on a hot day with heavily loaded lines. I mean, 20, 30 feet easily and those are some of the problems that frankly we are all struggling with. I think if you talk to Idaho Power, and PacifiCorp relative to the July 2nd outage, they would say they cannot figure out how that line sagged into a tree; that it was well beyond anything that they had contemplated, even though that was an isolated incident as compared to what we were dealing with.

Mr. DOOLITTLE. That was one incident. I think there was another one. The two incidents of this type occurred about a month before the August 10th incident and I am just wondering, did that set off warning bells for anyone? In light of what subsequently happened where essentially the same type of thing happened.

Mr. HARDY. It should have and it did not.

Mr. DOOLITTLE. As you have analyzed the structure with BPA, now with hindsight, why did it not?

Mr. HARDY. I think—those outages were on more lightly loaded lines. It was a case of not expecting that those lines would be integral to the support of the AC system and a matter of still struggling with what appeared to be other more significant problems that were the cause of the July 2nd outage. These lines occurred in the July 13th and 14th, I think.

And we were still focused on the voltage support/voltage collapse phenomenon, in this case, as it affected Idaho Power service territory and how that created a cascading outage that came through our system. As a result of that kind of focus and a variety of management reporting issues within the particular districts involved, we did not pay sufficient attention to that. In retrospect, we clearly should have.

Mr. DOOLITTLE. Just for my information, a 500,000 volt line, is that the biggest line?

Mr. HARDY. That is the biggest one that we have. There are some, some sections of the country have 765 lines and that is about the biggest in the U.S., I think.

Mr. DOOLITTLE. Well, what is the diameter of a 500,000 volt line anyway?

Mr. HARDY. About like that. Probably six to eight inches for out typical bundle of three conductors. I mean, these are big, big lines. They are not something that even de-energized you can horse around manually. It is something that requires high powered equipment to deal with.

Mr. DOOLITTLE. So I guess wherever you have these passing through you have roads nearby to get that equipment into? Is that how it works?

Mr. HARDY. That is right. You have to have access roads to get in. Typically, these are—at least the 500 and 230 lines are all on steel towers as opposed to wood poles, pretty massive kinds of steel structures. You have to have access roads sometimes in pretty remote territory.

For example, one of the complicating factors that we had in responding in the vegetation management area were the significant floods in the Northwest in the February timeframe that wiped out a variety of our access roads. Some of these areas that we simply could not physically access until the roads were repaired. So there were a variety of complicating factors in retrospect that prevented or inhibited our ability to provide adequate maintenance.

Mr. DOOLITTLE. Has there been a drop in the reliability of the Corps facilities over the last 10 years, in your opinion?

Mr. HARDY. John?

Mr. VELEHRADSKY. I do not know whether I could address reliability. We have had a drop in the availability of units.

Mr. DOOLITTLE. Because it seems to me I recall in another hearing seeing that projected.

Mr. VELEHRADSKY. Yes.

Mr. HARDY. I would make the same observation, Mr. Chairman, that Mr. Velehradsky did. I could not comment per se because I have not seen statistics on reliability, but there has been a definite drop in the availability of units and there are a variety of factors associated with that, not the least of which I think is the Federal appropriations process.

Mr. DOOLITTLE. Well, do you think there is a problem with the government's maintenance, then, of the equipment, since I guess that is what the appropriations process would relate to?

Mr. VELEHRADSKY. We do have units that need to be rehabilitated. We have a study underway, for example, right now at Ice

Harbor for rehabilitation of the units at Ice Harbor, so there is a process underway.

Back in about 1989, there was a change in the way we funded those kind of activities. We went from the operation and maintenance account to the construction general account, so I think we are moving in a direction to get more units available.

Mr. DOOLITTLE. Mr. Hardy, the WSCC has recommended mandatory membership and the ability to issue sanctions. What is the administration's position on the Federal entities being subject to WSCC sanctions?

Mr. HARDY. I do not know that the administration has formally addressed this. I can tell you my personal position is that is appropriate and if there are constitutional or other issues, I am sure we can work out the requisite agreements with WSCC to fix those. Typically, we have complied with virtually all WSCC recommendations, so from Bonneville's perspective, I do not see that as a problem.

Mr. DOOLITTLE. I want to go back to this proposal that you are making to modify how you can, in an emergency, declare an emergency and re-operate the dam when you have the fish flows involved. Is that a change that the three agencies can just make amongst themselves? What sort of action is that going to take in order to be implemented?

Mr. HARDY. I think it is possible that with the agreement of the three agencies we can do that but there are a number of predicate steps. First we need to complete the voltage support study so we can identify in a quite precise fashion what benefit this provides.

I do not want to go back to the fish interests in the region, Federal, State and otherwise, until I can tell them exactly what I think the exposure is and what the choices are vis-a-vis other measures that we might institute.

Secondly, it would require—and we are proceeding with this now—very extensive consultations with the State fisheries agencies, the Indian tribes, the National Marine Fisheries Service, and the U.S. Fish and Wildlife Service. Everybody would then have a clear understanding under what conditions this would be done and how it would be done and, probably most importantly from their perspective, if it is done what are the mitigating actions that Bonneville, the Corps, the Bureau of Reclamation would take to try to minimize the impact on fish. I think we need to be clear on all those points, and then I am optimistic that we can reach some agreement to make this happen.

Mr. DOOLITTLE. For what period was The Dalles re-operated? From when you began it on Monday, for how many days did that go on?

Mr. HARDY. It went on through about mid-afternoon on Thursday.

Mr. DOOLITTLE. OK. So——

Mr. HARDY. We were doing this on almost an hour-to-hour basis with Pacific Gas, checking with their dispatchers and their systems operations people on what the loads were, what they needed, how serious their circumstance was. During that time I was talking several times to Bob Glen, who was their chief operating officer, at the policy level to make sure that we had a clear sense of what was happening. So it went on for three-and-a-half days.

Mr. DOOLITTLE. And do you have some sense or is there some estimate of how many fish were killed or negatively impacted during that three-and-a-half days?

Mr. HARDY. I would say there were about 2000 juvenile fish total and probably half a dozen endangered juvenile fish.

Mr. DOOLITTLE. Half a dozen endangered fish?

Mr. HARDY. Yes, sir.

Mr. DOOLITTLE. Which is the real reason the fish spills are being done, right?

Mr. HARDY. That is correct.

Mr. DOOLITTLE. And the value—just as long as we are talking here, if we have a half a dozen endangered fish, what is the value of the power generation that is being lost as a result of the fish spills?

Mr. HARDY. I would like to answer that one for the record, Mr. Chairman. I would have to be specific about that particular spill operation.

[The following was submitted:]

LOST POWER GENERATION DUE TO FISH SPILLS

During the emergency (August 12-15), spill at The Dalles was reduced. This reduction resulted in increased generation at this project of approximately 60600 megawatthours or 361 average megawatts for the week (7 days). At the prevailing rates for surplus energy during that period, this amount of energy results in about $1.0 million in sales. Following the emergency, Bonneville provided spill for an additional four days resulting in offsetting loss in sales.

Through evaluations of fish spill required under the 1995 National Marine Fisheries Service' Biological Opinion, Bonneville estimates that the spill program results in lost revenues averaging $38.3 million per year. This is an average of 50 water years with a range of $2.1 to $93.7 million. This cost includes spill at the mainstream projects according to the Biological Opinion provisions.

Similar analysis for The Dalles projects yield an average cost for fish spill of $16.6 million with a range of $0.8 to $39.3 million.

Mr. DOOLITTLE. I mean, would you guess, is it in hundreds of thousands or millions of dollars?

Mr. HARDY. Probably the latter.

Mr. DOOLITTLE. OK. I just think it is important that we bring these things out, for half a dozen fish.

Now, were the McNary Dam units configured differently, Mr. Hardy, than BPA understood them to be?

Mr. HARDY. I think that we did not, and I do not know that the Corps did, fully appreciate the way that the McNary units would react when faced with the kind of voltage oscillation circumstances that occurred after Keeler-Allston went out.

I cannot answer whether they were different than other units or not, but we did go after the outage occurred, go with the Corps and with a team of WSCC technical generation experts, and we reset the exciters. We are now in the process of replacing the associated control relays so they will not trip off line if exposed to a similar kind of circumstance.

The WSCC panel that has looked at this has agreed if we complete the installation of that equipment, which should occur next week, and then test it in accordance with a testing protocol that we have reviewed with the WSCC panel, that that should be adequate to go back to relying on the full capability of the McNary units. I would expect that we would have that fully completed within the next 30 days.

Mr. DOOLITTLE. Mr. Bonsall, do you have anything that you want to share in that regard?

Mr. BONSALL. No, sir. I do not.

Mr. DOOLITTLE. And Mr. Velehradsky? What do you think went on? It seemed like there was some discrepancy, somebody thought that these were different than in fact they were.

Mr. VELEHRADSKY. Well, basically we had set them to certain limits and they performed well above those limits and so that is all I can speak to at this point. They performed about 5 minutes above the limits that we had set them.

Following the disturbance, I think Bonneville, WSCC, and ourselves and others looked at the situation and that is when the relay issue was discovered. We had a faulty relay, and we needed to set some tap settings on exciters that were a little bit out of tune. So those actions have been taken care of.

Mr. DOOLITTLE. Why were they out of tune or why did you not know they were out of tune?

Mr. VELEHRADSKY. They had not been tested in that state, the dynamic state, I believe.

Mr. DOOLITTLE. Well, is such testing in a dynamic state thought to be the best industry practice?

Mr. VELEHRADSKY. Well, what we are going to do is with Bonneville and the Western States Coordinating Council is we are going to train our operators and maintenance folks in that testing procedure and we will have a more rigorous testing program in the future.

Mr. DOOLITTLE. Mr. Bonsall, with Salt River, do they do this kind of dynamic testing?

Mr. BONSALL. You know, I would have to answer that one for the record myself. I need to check on that, Mr. Chairman.

Mr. DOOLITTLE. OK. I am just trying to get some sense. It seems like they certainly should have. Maybe we can ask our investor-owned utilities when they come up here in Panel III what their practice is, but I think it would be interesting to get that for the record just to see the comparison.

There is a recommendation, Mr. Bonsall, on page 16, or a comment, of this disturbance report which is very thorough, it says, "All transmission owning members shall evaluate the need for changes in the tree trimming policies of the U.S. Forest Service and other Federal land agencies and submit recommended enhancements to WSCC." Could you comment upon that? Are there problems with the tree trimming policies of the Forest Service?

Mr. HARDY. Mr. Chairman, if I could, I do not want to speak for WSCC, but I think I know what the recommendation is trying to get at.

Mr. DOOLITTLE. OK.

Mr. HARDY. And it is one of our 46 in our vegetation management problem. We all have lines that cross Forest Service and BLM lands and there are a variety of different standards, particularly environmental standards, when you can use herbicides, when you cannot, what you can cut, what you cannot, when you have to do an environmental assessment, when no environmental work is required, when is some greater environmental work required, etc. and I think it is fair to say, given the organizational structure in those two agencies, in the Forest Service in particular, that there is not complete consistency among different districts as to what requirements are. That is tremendously frustrating to a utility, whether that is a federally owned utility like Bonneville or whether it is an investor owned utility, relative to executing a consistent vegetation management program over 15,000 miles worth of right-of-way when you have 20 different standards in different areas that you are trying to comply with relative to the degree of environmental paperwork that needs to be done or what you can actually do on the ground. And I suspect that is part of what the WSCC recommendation is trying to get at.

Mr. DOOLITTLE. When you say different districts, do you mean different national forests or do you mean different ranger districts within the same national forest?

Mr. HARDY. I mean different ranger districts within the same national forest.

Mr. DOOLITTLE. They have different standards?

Mr. HARDY. All I can tell you, Mr. Chairman, is there is considerable variation. There is a lot of autonomy given to individual districts for I am assuming legitimate management purposes, but that leads to considerable variation in what the requirements are for particularly environmental compliance relative to various aspects of what I would consider an adequate vegetation management program. We need to work more actively and aggressively with the Forest Service and with BLM to try to get better consistency so we can execute that kind of a program.

Mr. DOOLITTLE. Let us see now. I think your statistics, Mr. Hardy, on the frequency and duration of transmission line outages indicate that on your 500,000 volt lines BPA has a frequency of outage 60 percent higher than the national average. What do you attribute that figure to? Why is it higher?

Mr. HARDY. I frankly do not know, Mr. Chairman. I would point out that our overall reliability rating, 230 and 500, is better than the national average by a significant extent and why the particular 500 rating is worse than national average I would have to answer for the record.

[The following was submitted:]

FREQUENCY OF OUTAGES ON 500 KILOVOLT LINES

The reliability statistics in question, the System Average Interruption Frequency Index for 500 kilovolt lines, reports outage frequency on a per-line basis. Since Bonneville's system has a large number of rather long 500 kilovolt lines, any given 500 kilovolt line on our system has a greater exposure and potential for outages than shorter 500 kilovolt lines. Therefore, when compared with utility systems with shorter 500 kilovolt lines, outage frequency rates of longer lines will appear relatively higher.

In addition, many of our 500 kilovolt lines traverse arid, inland areas where the frequency of lightning strikes is great. Lightning-induced outages tend to be very short in duration, often only a few seconds long. The System Average Interruption Duration Index of outages for 500 kilovolt lines shows Bonneville with considerably better performance than the national average as reflected in the Institute for Electrical and Electronic Engineers survey.

Mr. DOOLITTLE. According to the WSCC report on the August 10th outage, some power system stabilizers used to, I understand, damp system oscillation were not operational at The Dalles. In fact, I guess at The Dalles there were five units on line and three of them were without stabilizers and at John Day 13 units on line and four without stabilizers. Do you know as of August 10th how long had those problems existed?

Mr. HARDY. I would have to provide that for the record, Mr. Chairman.

[The following was submitted:]

POWER SYSTEM STABILIZERS

The stabilizers you cited have been out of service since prior to 1993. Power system stabilizers are installed on most Western Systems Coordinating Council generators to provide damping of oscillations. For low frequency oscillations, such as occurred on August 10, it is the combined action of many power system stabilizers that are expected to provide damping. The absence of operational stabilizers on six units at John Day and The Dalles were not deemed to be critical.

Mr. DOOLITTLE. OK. Would you, please? I just wondered. And how significant are these stabilizers anyway? Apparently the units can be operated without them. I just wondered what risk is there to doing so.

Mr. VELEHRADSKY. We can provide that for the record.

[The following was submitted:]

SIGNIFICANCE OF STABILIZERS

The generators at The Dalles Dam and John Day Dam can be operated without power system stabilizers. For the August 10 low frequency oscillations, the combined action of many power system stabilizers is important, and outage of a few stabilizers will have only a small effect. The Western Systems Coordinating Council requires that each company have at least 80 percent of stabilizers in service at all times. The United States Corps of Engineers is almost always in compliance with this requirement; on August 10 seventy of seventy-seven stabilizers were operating.

Mr. DOOLITTLE. Sure. OK. Well, I think I have covered most of my questions of this panel.

Mr. Hardy, if you would not mind, would you be available to hear the other two panels, since generally the whole hearing relates to BPA?

I would like to thank all three of you gentlemen for your testimony. It has been very helpful. We will excuse panel No. 1 and invite panel No. 2 to come up.

[Witnesses excused.]

Mr. DOOLITTLE. Panel No. 2, if you gentlemen would remain standing? Will you raise your right hands?

[Witnesses sworn.]

Mr. DOOLITTLE. Thank you.

Let the record reflect each responded in the affirmative.

Please be seated.

We have with us today on this panel P. Gregory Conlon, President of the State of California Public Utilities Commission, and Renz D. Jennings, Chairman of the Arizona Corporation Commission.

Gentlemen, welcome. As you can see, it is a fairly free-flowing discussion, so do not worry about the lights. They just kind of give you an indicator of where we are on this and at the conclusion of both of you testifying, then I will ask you some questions.

Mr. Conlon, you are recognized for your testimony.

STATEMENT OF P. GREGORY CONLON, PRESIDENT, CALIFORNIA PUBLIC UTILITIES COMMISSION

Mr. CONLON. Thank you. I want to start by welcoming you to California. I know that you are a California legislator, but I think the committee is a Federal group, so I want to welcome you here to California for the commission and the Governor.

Mr. DOOLITTLE. Thank you.

Mr. CONLON. I think the WSCC should be commended for the excellent report that they gave on the outage, as well as its continuing work to system reliability. And since they have already gone through the causes of the outage, I do not think I want to do that.

I thought maybe I would go off my statement a little bit and just let you know what we did in California after the outage to confront the problems that they just talked about.

Mr. DOOLITTLE. I think that is great. Your statement is part of the record, so please feel free to make any comments you would like, knowing that that will, of course, be in the record any way.

Mr. CONLON. I think on Sunday it became apparent with the temperatures over 110 degrees in the Valley with the number of units that were out that California had a very serious problem starting Monday and Tuesday when everybody went back to work, so at the commission we worked with the Governor's office to see what degree of emergency we needed to deal with and we concluded after discussing it with the companies that at a minimum we would restrict air conditioning usage of all 220,000 State employees during the following week, so we did take that action.

We went to Oregon on Monday morning with an emergency meeting of WSCC and I did participate in the press conference to help assure the environmentalists that we did have an emergency in California, that it was a serious matter and their decision to declare an emergency to put The Dalles units back up was appropriate.

We helped the company get the message to consumers in California that on Monday, Tuesday and Wednesday that we had a very serious problem and everybody should conserve electricity, so that was about all we could do in that short timeframe, but we worked with PG&E, particularly PG&E because they had lost the two Diablo units which was making it very critical and their reserves were very low during that period because we had record peaks almost each day of that week.

So it was very touch and go there for those few days, but we were able to get through it. The companies, they will, I am sure, confirm that, restrained their interruptible customers and we were able to get through those 3 days by everything we could possibly do.

So I do think that this is a good example of how to prevent future outages. I think California as well as the West cannot tolerate another outage of the magnitude we had on August 10th.

I think it gave us all a wake-up call and I think California is a three strikes you are out State, that we have had two strikes and I know that if we have a third strike of a great magnitude that several of us will be—the fingers will be pointed at us, so I think that

I want to try and assure you that the California commission is going to do everything we can to look at this and deal with it on an effective basis.

The lasting effect of the outage has been that the de-rating of the north-south intertie to California from 4750 megawatts down to 3200 pending the WSCC's review and I think California, we have already had a significant loss as a result of the August 10th.

I am sure it is several million dollars, tens of millions of dollars, between the customers and the power that we lost during that period, that we do not want to continue to do that. So we are hoping that that intertie situation can be corrected at the minimum by next summer so that we would have full availability of that power for the companies and the States that are south of that border, the Oregon-California border.

And as for what should be done in the future, we think it is clear that the inspection, maintenance and testing of transmission facilities should be strengthened. The WSCC report details many instances of inadequate tree trimming and equipment failures. I think five flashovers occurred on August 10th. And in California, I am personally recommending that our commission implement periodic inspections by our staff of our high voltage transmission system, as well as a review of the utilities' line patrol and tree trimming records.

In looking back at our own staffing, we have safety responsibilities for electric, gas and rail procedures and we had cut back on our electricity because of appropriations problems that we talked about earlier, and so we are looking at beefing that up now and one of the steps that we would consider doing is personally having our staff inspect some of these facilities.

Second, the operating procedures and training of operating personnel need to be reviewed and strengthened and I think that was brought out in the report, that the WSCC notes that the operators were unknowingly violating WSCC reliability criteria.

And, third, improved communications and coordinations between all utilities and control area operators appears to be needed. The one and a half hours before the outage BPA, has indicated in the report, did not communicate the loss of the three 500 kv lines. And, as indicated, such information if communicated may have alerted other control areas to take mitigating evidence.

There is also evidence that the communications within the control area could be improved and I think you got into that with your line of questioning between the Bureau and the Corps and BPA and I think the focus of those units, not being from the Northwest and not having the political sensitivity that goes on in the Northwest, I think in the peak summer months we would like to see a higher focus on electric production, but they have to make those decisions. We would certainly welcome it and hopefully they can make some adjustments.

I believe the system reliability requires enforceable standards and rules and there is a clear need to create regional standards with a mechanism to impose penalties on entities that fail to operate within those standards. We believe those penalties would need to exceed the cost of failure to comply with the standards. Otherwise, if it is cheaper to not comply than it would be to get the fine, then we would have ineffective fines.

So I think the four steps, improve inspection and maintenance operating training and improve communication and coordination and enforceable standards, are the goals that we would hope that everyone would achieve from this lesson.

Now, how do we do that? I think as State regulators, we will have an important role to play, but most of these are—at least for the non-Federal facilities, because we do do site reviews, we do constructions standards, we perform inspections and enforce safety requirements, so these are the kind of standards that we can deal with on a regional basis.

But standards set by a single State could not be sufficient, so we need to coordinate with the other States and I think there are several ways we can do that. First, I think reliance on an independent system operator, the use of an interstate compact or ultimately maybe an international treaty because we have both Canada and Mexico involved in this grid. I mean, we cannot isolate the grid. These grids go into these countries and then if there are problems there they are going to affect us just as much in California as if they were in Mexico or Canada.

We certainly need to increase coordination between the States and interstate compact and increased authority needs to be given to the region groups such as WSCC.

So if I have a couple more minutes, I just could amplify on those couple——

Mr. DOOLITTLE. Please.

Mr. CONLON. OK. I think on the ISO, California is moving to promote competition in the electric industry and maintaining system reliability is a critical concern. I know in my study of the UK situation that was their primary concern also, that the lights stay on. And I think if we start open competition on January 1, 1998, and we have a major incident right after that, that it would be very unfortunate. So I think we need to be very sensitive to that.

And I think California's answer to reliability will be to create a statewide, independent system operator which will set and maintain system reliability standards and we have hired a gentleman, David Friedman, who you may or may not know, to help us in the next few months to keep that process going. And I think that we are fortunate to have David to help us.

And then as I mentioned, I personally recommend that we develop a region-wide ISO, independent system operator. And as a transition, I know that we are developing our own ISO in California and the Northwest is doing the same and I am sure there will probably be two or three others that form, but ultimately I think a one-region ISO would be the ultimate in reliability because one control center would have the ultimate information in front of it. It would have communication systems that would eliminate some of this communications problem, at least that is our view and I would certainly support that as a long-term goal.

Now, the use of an interstate compact is another way to try and do that while the ISO is developing and the California legislature has directed our commission to work with the other States to get an interstate compact developed if we can in the Western grid.

Under this compact, all Western States would join together to develop enforceable standards and protocols to protect the reliability of the region's electric supply. And since it would probably take some legislation, your Committee could certainly be a sponsor of any legislation that we would need at the Federal level. Since the Western grid is becoming international, it even may get into some kind of international treaty or amendment to NAFTA or something to get those other two countries involved.

Improved reliability coordination may not require an interstate compact if each state or province on its own would require compliance with uniform standards, such as the WSCC, and if we implemented our own program for enforcements. Models for this type of action could include the Western Interstate Energy Board and various other boards that have been established to coordinate rulemaking for multi-State utilities.

And a final possibility would be to utilize the existing reliability council, the WSCC, to functionally perform as an entity that both sets and enforces regional standards. For this to occur, the organization and function of the WSCC would have to change. As others have said, membership in the WSCC would have to be mandatory for all grid users. State regulatory agencies would have to play a larger role in setting WSCC policy and WSCC would need sufficient staff and, again, more importantly the WSCC would need to make sure that failure to meet its standards could result in enforceable sanctions, as I previously mentioned. Each of these options for creating regional enforceable reliability standards is worth pursuing.

I have recently sent a letter to the members of the Committee on Regional Power Cooperation, which consists of the State commissioners here in the Western United States, asking them if they would work with California in establishing regional reliability standards and, additionally, this issue has been discussed at a recent meeting in Santa Fe of this group and we are going to meet 2 weeks from now in San Francisco and hopefully some kind of a compact will result.

In conclusion, I would like to say that ultimately reliability is the responsibility of all of us, the grid users, the utilities, the control area reliability councils, the State regulators, the Federal agencies and even customers as we move into a competitive market. So as this competition increases, it will provide both challenges and opportunities and we look forward to working with each of these groups as well as the committee to ensure an efficient, reliable electric system in the West.

Thank you.

[The prepared statement of Mr. Conlon may be found at the end of the hearing.]

Mr. DOOLITTLE. Thank you very much.

Mr. Jennings, you are recognized, sir.

STATEMENT OF RENZ D. JENNINGS, CHAIRMAN, ARIZONA CORPORATION COMMISSION

Mr. JENNINGS. Thank you, Mr. Chairman. I appreciate the opportunity to bring a non-California perspective to this or a non-California-Pacific Northwest perspective. We consider ourselves somewhat remote from the triggering events of this, but yet we had a fair amount of consequence.

I would also like to thank President Conlon for his kind offer of help. He was not quite sure where Arizona was in terms of difficulties we might be having and he offered to intervene on our behalf. I guess they call that leveraging one's position with the utilities. We do appreciate his kind offer.

First of all, I want to approach this with a certain amount of humility. This is pretty technical stuff and I am not an engineer or an electric reliability expert.

Mr. DOOLITTLE. I am not either, so that makes two of us.

Mr. JENNINGS. All right. A couple of policy folks here with some perspective.

The two outages have left us with sort of an interesting risk management problem and we certainly know we will not be able to eliminate completely the outages, but we can develop reasonable risk management strategies that will reduce the possibility and impacts of future outages.

In order to address this risk management problem, we need to look at six aspects and they are: the need for more and better quality information; the need for credible commitments to reliability; the need for better communication among utilities and others; the need for a clear delineation of responsibility; the need to develop better damage control; and the need for participation by all appropriate parties in the development of risk management solutions.

Let me take each one of these and discuss them a bit.

First, the need for more information relates to our need to better understand the Western integrated electric grid under a wide variety of possible operating conditions. Rather than merely looking at likely single contingency scenarios, known as N–1 scenarios, we need to have WSCC and utilities look at models of multiple contingencies known as N–2, N–3, et cetera, scenarios.

Second, we need to elicit credible commitments to reliability from all participants in the interconnected grid. This should start with mandatory membership in the WSCC or at least mandatory requirements to meet WSCC minimum reliability standards. A performance bond could be required as a sign of credible commitment and could be attached in case of failure to comply with reliability criteria.

Since the two major Western power outages this summer in July and August, we have heard over and over again that the safeguards built into the Western interconnected grid worked as designed. The system islanded power plants were tripped to prevent equipment damage and loads were shed to help stabilize the system, thereby avoiding a complete shutdown of all Western power generation. Yes, it appears that the protective mechanisms worked after an irreversible problem started the blackout.

While it is important to improve the system in ways that will limit the damage from a system outage, it is far more important to take steps to avoid the conditions which led to the start of the outage.

This brings me to a major concern that we in Arizona have. If in fact the NERC and the WSCC criteria and requirements are appropriate, there is still a major problem ensuring that those standards are enforced. Unless there are some credible penalties or sanctions applied to those who fail to meet the standards or shirk their responsibilities, we will have a reliability system that works in theory, but not in fact.

Enforcement and penalties can be handled in a number of ways. First, WSCC and other regional reliability councils could take on the responsibility of enforcement of penalties. Second, the Federal Government could take the responsibility. Finally, the various State PUCs could take on the enforcement and penalty responsibility. However, achieving uniformity among States might prove difficult.

My preference would be to have WSCC perform this function. WSCC would monitor and measure compliance. Although NERC has the national responsibility for reliability, it is not staffed or prepared to take on an enforcement mission. Concerted State action might be much more difficult than having one entity in each region, WSCC and the other regional reliability councils, handle the enforcement of standards.

Effective enforcement would only be a possibility if mandatory membership were made possible by FERC ruling or by Federal legislation. States could require membership, but this would only work if each and every State made membership a requirement.

Third, we need better communications among the participants in the Western grid. It is very likely that if we had a better inter-utility communication system on August 10th that the outage might have been avoided or at least it might have given enough warning so that the resulting impact may have been reduced.

We need a real time disturbance alert mechanism so that operators on the integrated system can get early warning of problems which may affect their system operation.

Fourth, we need to ensure that as we move to a more competitive electricity market there is a clear delineation of reliability and the responsibilities either through market mechanisms, through contracts, through State or Federal regulations, through independent system operator mechanisms or through WSCC requirements.

Fifth, we need to develop better damage control mechanisms. These could include better islanding methods. Arizona is a relatively small State in terms of population and power usage compared to our neighbor to the West, so to the extent that California utilities and Northwest utilities ignore potential problems on the Western interconnected grid, the resulting outages will probably continue to have a major negative impact on Arizona's electric system.

Whatever happens in the California power markets has a significant impact on all of the adjoining States. Since California is going to lead Western States in the move toward restructuring and competition in the electric utility system starting in 1998, they are the earliest at this point and continue to be the earliest, we hope that adequate care will be taken to ensure that all competitors in the California market meet reliability standards, along with a fairly explicit and equitable load shedding protocol. I think that would be our major issue, the load shedding protocol.

It is my understanding that on July 3rd, the day after the big July 2, 1996 outage, a similar problem occurred and Idaho dropped load for the entire City of Boise, which kept the entire system in the West from going down again. This incident and the smart and timely actions taken by Idaho operators should be proof that a load shedding protocol may limit the severity of outages. It also should perhaps underscore the potential in a more competitive market doing the right thing is less intuitive, where they clearly did the right thing and saved the rest of the West from going through a subsequent outage.

Finally, we need to encourage the participation of all appropriate parties in the process to develop solutions. In particular, the State PUCs need to be involved as honest brokers.

A few years ago, it would have been unlikely for State regulators to be welcomed into this kind of problem solving process, but I think the times have changed, the process is much more open to a broader set of inputs.

Participation of State PUC representatives in the various Western RTGs has been beneficial and has opened new avenues of communication among the parties involved. We need to continue to work together in order to understand and solve this complex reliability problem. Indeed, PUC regulators bring a ground level public interest perspective of concern for overall reliability and economic efficiency that individual market players may not necessarily bring. Without this broad perspective, the narrower interests of market players may dominate reliability protocols.

The regulators can help develop a balance between system reliability obligations of non-WSCC members without allowing WSCC members to inhibit the transition to competition under the guise of reliability. While this will be challenging, I and other regulators are ready to meet these challenges.

That concludes my statement. If I could just read four bullet points from a recent declaration of independence, it is why the transmission and system operation must be truly independent from the ownership of generation, and I will just read four bullets. This was a declaration of independence that regulators throughout the country have looked at and many have embraced.

In competitive electricity markets, all generators will benefit from high prices, while customers will benefit from low prices.

In competitive markets, higher prices achieved through any action, including control or transmission system, by any generator or group of generators will benefit all generators.

In the absence of a clear structural solution such as divestiture, we must create solutions equivalent to a non-voting transmission trust. Generating companies must cede all control of their transmission lines to the ISO. They will be entitled to fair compensation on their investment, but afforded no opportunity to influence the use of those lines.

And, finally, only when transmission constraints cannot be used to leverage above-market value from generation assets will the public's interests in genuine competition be well served.

I think that is a good description of the concern that State regulators have as you balance the interests between a reliable system and a competitive, efficient functioning marketplace.

[The prepared statement of Mr. Jennings may be found at the end of the hearing.]

Mr. DOOLITTLE. Thank you.

The comments you just made, Mr. Bonsall explained how generation, transmission and distribution all relate to each other, and yet the trend of the market is to take entities where all three of those are united, which I presume is the case with PG&E or Southern California Edison or other investor-owned utilities in many cases, and we are going to go to the Federal model, I guess, where all three of those things are separate.

I mean, that is sort of a paradox in my mind. We recognize that to deal with this issue of reliability all those three things have got to be coordinated and yet the trend we are going is in the opposite direction, is it not?

Mr. CONLON. Well, I guess in California, since we are kind of leading the way on doing this, maybe I should comment on our thinking there.

I think today in California we have at least 400 plants that are not utility-owned generators, so I do not think it is true that generation is necessarily tied into the integrated system. We have more independent generators in California than any State in the union.

As far as the transmission is concerned, our expectation is with an independent system operator that we will enhance the reliability. Instead of having six control areas in California, we will basically have one ISO that will be able to dispatch the generators in an efficient manner, based on prices of each generation, so we will get an efficient dispatch based on the economics and yet he will have the overriding control. If he believes that he has a problem, whether it is voltage support or spinning reserves or anything else, he will have the ultimate power to order those units to run.

So I think that in my view that is enhancing reliability and it not only picks up the IOUs but it includes the munis and on the transmission system, I think the munis are about 40 percent of the State's transmission. So assuming they agree to participate in the ISOs, and I think that is everyone's expectations, for the first time in California we have one entity that controls both the transmission of the munis and the IOUS, and it would be done on a statewide basis so that I think that our reliability for the State would be enhanced and the economics should be improved because of the ability to dispatch on a wider basis.

Mr. DOOLITTLE. Now, this entity would not include, would it, the Federal power marketing administrators?

Mr. CONLON. Well, you know, we are just dealing with California. If this expands to a regional basis, I think you do have the same challenges in the Northwest that we have had here in California about separating the generation, the marketing of generation and the dispatch function. And I know from my discussions, informal discussions, with BPA that there are discussions about separating off the marketing function of the power from the dispatch of the transmission systems so that they would not have an internal conflict, which is what would happen today.

And I do not know how the Corps and the Bureau would dispatch generation. In the ultimate, I guess the ISO would have to have some control over the units of the Corps and the Bureau, taking into effect the mitigation, the navigation and other responsibilities they have. And I do not know how they would do that, but it seems to me that to follow the model of an independent system operator that they would have to have dispatch control of those units.

Mr. DOOLITTLE. Since one of the things this whole issue has brought out to me is how—I mean, clearly, we go to other States to get not only our water but our power. I mean, it is not just confined to within the State of California, so is not this idea going to have to expand beyond the State boundaries?

Mr. CONLON. Well, we certainly would recommend that and I think—we had a meeting 2 weeks ago in New Mexico with the Department of Energy and the National Association of Regulatory Utility Commissioners and I think there was spontaneous recognition of a group of about 1000 people in the industry that regional ISOs were the obvious end result. So I think there was recognition at that meeting. And I think a year ago or 2 years ago that would never have occurred.

Those people would have never said, well, hey, we are going to give up control of our transmission system to an independent operator and he is going to dispatch the power. I mean, they would have said you have to be kidding.

So I think the process has come a long way in the last 2 years and I am optimistic that the reliability will be improved as we get to a larger and larger ISO for more and more States.

Mr. JENNINGS. Mr. Chairman, I would agree. I think we are heading in that direction, not drifting, necessarily, totally rudderless, but I think there is a sense that we want to take this in increments. Do the reliability thing well and first to make sure that there is not—that the market power issue is adequately dealt with and that is, I think, what we have addressed in the declaration of independence.

But there are some regional—California is perfectly rational to have done what it did early, it got high prices and there is a lot of cheaper power out there in the marketplace and I think the intent is to reprice power lower in California and it probably will increase prices elsewhere. So there is naturally places with the lowest cost power are not particular anxious to transfer that highest and best use or highest and biggest dollar to take what they have had as low cost power and transfer that in to California. So there is some incremental reluctance there, but I think in time as the market evolves there will be independent system operators. Perhaps Arizona, New Mexico, for example, might be one ISO, California will have one ISO. Probably the Pacific Northwest might be one ISO. I think Colorado has already got one in the works.

Mr. DOOLITTLE. What about the PMAs, though? Where is Bonneville going to fit into this or WAPA?

Mr. JENNINGS. Well, Mr. Chairman, I am under oath and I am not supposed to dissemble or do anything bad here today, but I do not want to touch that one. That one is going to be—I have not thought it through sufficiently. That is not an easy piece. This system evolved over a number of years to work pretty well and we have gone down just two absolutely divergent roads and now we are going to go to a sort of overall competitive marketplace and there are clearly some large issues. I get service from the Salt

River Project here. He is going to hear me and they are going to read the transcripts.

No, I am not ready to sort that one out for Congress. I have not sorted it out in my own mind. But it is going to be an issue that will be with us for some period of time.

The commission in Arizona has just opened up the marketplace to competition, but we do not regulate the Salt River Project and we have given two options. One, if we can figure out some way that they can agree to be bound by the same terms and conditions of other market players, that there may be some voluntary way to do it. The other choice we gave them is to go to the legislature and take their chances.

Now, they do not like either of those choices, I am sure, but it does not make any sense to have islands of non-competition in a world that is moving toward competition. I know the project is wrestling with that issue and others are trying to figure out how to make the rules of the game of competition fairer and everybody sees—if you get investment tax credits and you are a muni, the muni thinks that is bad or that is a comparative disadvantage, but if you do not pay full taxes and have municipality status and cheap tax-free bond status, the IOUs are quick to rocket off on that one.

So it may be that Congress wants to deal with this and State legislative bodies, but at some point I think there will be a recognition that a seamless, smooth operating marketplace that is relatively distortion-free and offers high reliability is going to be in the public interest. How we get there, I am not sure.

Mr. DOOLITTLE. I am going to ask Mr. Hardy to comment.

Why not come up now because we might have some——

Mr. JENNINGS. Sorry to do this.

Mr. HARDY. That is OK.

Mr. DOOLITTLE. How do you see, Mr. Hardy, the power marketing administrations fitting into this new world of deregulation and competition and an ISO that is the absolute master of all these lines?

Mr. HARDY. I think it is not clear yet. The administration, Mr. Chairman, really has not gotten to the point of taking a position on this, so let me caveat anything I say by that.

Mr. DOOLITTLE. Right. Sure. I understand that.

Mr. HARDY. From my personal perspective of 20 years in this industry in a variety of positions, not just with the Federal Government, but in various positions in both the private and the public sector, I think Bonneville and WAPA probably have to be part of an ISO. In the Northwest, my perspective is if Bonneville can be legislatively separated into two corporations, I think we should be the ISO in the Northwest. That begs the question of if you have a WSCC-wide ISO how that works, but clearly I think we need to and WAPA needs to be part of that.

How you work through the constitutional and legal questions associated with how Federal officials participate and to some extent get directed by non-Federal parties is a tricky set of issues. We are dealing with that in the Northwest right now.

The Northwest investor-owned utilities have formed or are in the process of forming an organization called Indego, which is their version of an ISO, kind of half an ISO. How that organization is formed, and how it relates to BPA's transmission system involves some very tricky questions of governance, and operations. For example, it is especially important to have scheduling and dispatch functions together. Whatever else you do with the ISO, you absolutely have to have those two things together or you are asking for trouble.

I think California is moving down that line fairly well. Frankly, I am worried about the Northwest in that respect. But you have a whole series of questions there and it may well be that legislation could facilitate that, but, like I say, we will have to deal with the administration to examine whether that is appropriate.

The administration is really waiting on the Northwest. The Northwest Governors, I think you may know, have convened a panel called the Comprehensive Northwest Energy Review to review Bonneville's status, what role should Bonneville play, not just in maintaining reliability, but in all aspects of this competitive marketplace in the Northwest. That panel should have a series of recommendations to the administration and to the Congress in December. Those recommendations will hopefully give us some clarity on what fork of the road we are on here.

Mr. DOOLITTLE. Do you gentlemen contemplate that the ISO is going to be in many cases some existing utility that volunteers to do that job?

Mr. CONLON. No, it will be an independent—in fact, that is one of the big challenges the State legislature had, was how to govern the ISO and in the original proposed decision or the decision we issued, the commission, we had a governing board that was made up of 15 members or approximately 15, less than half of which were utilities or municipalities, so the majority of those were non-generating producers.

Now, the legislature was not satisfied with that. They imposed a three-member board above that group as an oversight or an appeals board, if you will, that will be strictly public purpose representatives and we are going through the process now of recommending to the Governor names that would be appointed that would go in place on January 1, those three members. And Mr. Friedman is functioning in that capacity as an individual for the next 3 months so that the process keeps going but that board, it is essential it not be controlled by the generators or you have lost the independence that the word implies. An independent system operator would not have any interest or minimal interest in any of the generators.

Mr. DOOLITTLE. Nevertheless, you have to have the knowledge and the technical expertise of how to do it and that is why you are talking about splitting the two corporations, is it not, Mr. Hardy?

Mr. HARDY. In part and in part to eliminate the conflict between us being a major transmission owner and yet still having marketing rights to the output of the dams. The issue we are struggling with is the fact that that conflict is there and FERC is driving the whole industry in a direction of separating those functions. The statement of principles that was just read clearly indicates that is also where most of the States or State regulators are appearing to go.

The problem that that creates for Bonneville is that while separation is clearly necessary to have a viably functioning and competitive marketplace, it is in conflict with most of the rest of Bonneville's organic statutes, which say the administrator singular shall do A, B, C, or D.

So all of the legal responsibility and, probably more importantly, the political accountability is vested in this single decisionmaking official who has control over both the power marketing and the transmission assets. Added to this, Bonneville still writes a single check to Treasury each September 30th to repay the outstanding debt to the tune of some $800 million to a billion dollars a year that is a blend of power and transmission revenues.

That puts me in the position of if my power business is in trouble absent legislative separation, I may have a legal obligation to manipulate my transmission business to help out my power business if that optimizes the chance I am going to make my Treasury payment.

That is fundamentally in conflict with the way the whole rest of the industry is going. That has to be rationalized. Maybe it can be done administratively where you set up a process within the region for those conflicts, or maybe it should be done legislatively. That is one of the issues the Northwest Governors panel is debating right now.

I think the administration, and to some extent at least the Northwest congressional delegation, is waiting to see what the panel will recommend on this issue.

Mr. CONLON. But the important thing here is that the California utilities have given up physical control, operating control, of their transmission facilities to a third party.

Mr. DOOLITTLE. Now, they will retain, I guess, ownership.

Mr. CONLON. The ownership.

Mr. DOOLITTLE. Right.

Mr. CONLON. So BPA could, I guess, hypothetically BPA could retain ownership even if they did—but could give up control of the facilities or they could be the ISO and give up—it is a difficult issue how to separate it so that there is independence from the generation. But I just want to say that I think the Corps or the Bureau has a tremendous asset in these units that they obviously are not optimizing because they have other purposes.

As I have heard here today and in other hearings, that they have the fish mitigation, they have the navigation and the flood and all this other stuff, but they have the ability to make some money with those units. They are there for voltage support, spinning reserves and just power production to sell into the grid.

So I do not know—you know, I know the Federal spending is always cut back but it seems to me they could probably enhance their financial capabilities by being more aggressive in the market if their overall objectives would allow them to do that or if somehow it was legislated that they could do it.

I am just trying to use the analogy of the California situation with the munis and the Northwest situation with the Federal agencies and trying to draw—because this agency right here, the Los Angeles Department of Water and Power, is faced with the same decision. They are a municipally owned company.

What do they do with their transmission? What do they do with their generation? And then how do they operate their transmission? Because they are surrounded by investor-owned utilities who are going to be open to competition within 18 months or whatever number of months it is and it is going to be a tremendous pressure on them to do something.

Mr. JENNINGS. I wonder if I could go back to your earlier question that implied, well, should you not have the people who know the most about running this technical system be the ones designing it and the answer is yes and no. And I think you will get into that in the next panel.

We had a meeting after the outage of August 10th in Arizona and I thought one of the most prescient observations made was a fellow stood up and said, you know, here we have a system designed by economists that is to be run by engineers and yet there is a physics to all this, will the electrons really continue to flow if this system is really designed—so I think what we are doing in this next panel really gets at some of that.

And it is interesting, if you look at the next panel, I know in Vikram's case, he is the only one I know on the panel, but if you look at the Western Systems Coordinating Council sort of description of those events and what is going on here, you do not get quite the—you get just a hint that this governance issue is a big deal, but I think the brain storming group that will be on your next panel hinted at it even more broadly. This governance issue of who is going to be setting the rules of the road really makes a huge difference.

If it is all the suppliers, well, again, you are back to they will make it work out for suppliers. And, of course, the engineering criteria, we all want to have a reliable system, but it is going to be easy to hide behind how those criteria inhibit a low price world.

So just so I think my earlier comment, that regulators have been sort of—we used to be the goat in the manger at any of these gatherings, I think we are much more happily received these days because we sort of give a broader cover to the public policy issues. And I think, if I can give some comment on the panel to be, that appears next, that they will be well served if they figure out how to get some folks' perspective who are consumers into those decisionmaking bodies, to have some of that input. Otherwise, we may be cheated out of the benefit of going through all of this agony to develop ostensibly a competitive market which may not develop. It may end up just being a supplier's market.

Mr. DOOLITTLE. Your proposal in Arizona and California, this idea of deregulation and an independent system operator controlling the transmission, the companies that own these things get prorated credit or something, do they not?

Mr. CONLON. They get their normal return on their assets at a minimum on this, so they are not going to lose any profitability per se.

Mr. DOOLITTLE. Right.

Mr. CONLON. That is the concept.

Mr. DOOLITTLE. And you, Mr. Jennings, were referring to—I just want to understand the point you are making. California is going to have cheaper power, but that means it is going to be more expensive in some other place. Will you explain?

Mr. JENNINGS. Sure. Right now, Idaho residents have probably the cheapest power in the country. You can correct me if that is—they have very, very cheap power. It is almost hydro based, some coal. And it is just incredibly cheap, so they have built their entire economy around cheap power.

What California would like to do, undoubtedly, is to have access to cheaper power and so lower their average price of electricity. There is nothing irrational about that.

If you are a resident in Idaho, you want cheaper power. If you are a shareholder of Idaho Power, you want to sell into the power exchange because it is the last one in that sets the price. So whoever can make a profit by being last in of the Idaho Powers of the world can make a boodle of dough.

So I think therein lies some of the—it is the politics of envy. Anybody who has cheaper power costs, somebody else is saying, gee, we manufacture, too, and we would like to get a cheaper price, we are in competition with these people that are making this in such a such State.

I think the real risk is that right now everybody thinks that power is much cheaper than it really is and once we go through this, and I am glad that we had the outages, it has been a great wake-up call to put first things first. But there is certainly a lot of risk that this will not turn out to be—although the cheap power, in that right now there is an excess of capacity in the region and everybody else is selling that back and forth to each other right now. When this marketplace tightens up and the reliability criteria are built in, there is a lot of resistance to investor-owned utilities to go out and make some new investments on long-lived plant and so it becomes a more speculative deal to sort of plan that over the next 20 years that your millions of dollars, you are going to get a cost recovery.

Well, you used to get them under the old regulatory regime where your earnings are pegged directly to your investment. Here they are pegged to the marketplace. If the market goes up or down, you have some risks.

It is going to be a tightening up, I think, many people suggest in the next 4 or 5 years, just when all this competition transition we have gone through and then there may be another consequence that we have beefed up the transmission system and then as new technology comes on board, the micro generation, the solar stuff, fuel cells maybe, maybe not 5 years, but when that stuff starts to come in, we are going to have a whole new way of doing things potentially.

So there is a lot of risk out there and right now we are doing this on faith that markets work and that we will be able to get rid of a lot of the market imperfections and sort of figure out most of it on the fly. And we usually do reasonably well at that as a country. So I am somewhat optimistic, but some of the benefits probably are being oversold and at least it is worth considering whether that is the case.

Mr. DOOLITTLE. So you are saying, when you say tightening up in four or 5 years, you mean there is a relative scarcity today.

Mr. JENNINGS. Yes.

Mr. DOOLITTLE. And therefore higher prices.

Mr. JENNINGS. Yes. A lot of plants right now are slated to be decommissioned over the next five, 10 years.

Mr. CONLON. I would like equal time here, if I may, but I will let you go ahead and finish, Renz. I do not want to cut you off.

Mr. DOOLITTLE. OK. We will give you equal time.

Mr. JENNINGS. There is quite a large number of power plants that are planned to be decommissioned within the next five or 10 years. I do not know, something like 30 or 40 percent, some large component of the generating mix right now.

Mr. DOOLITTLE. And are they really decommissioned or are they just refurbished and keep on going?

Mr. JENNINGS. Well, they have been. They have been refurbishing them, but they can only do that—I think we are going to inescapably come to the point where there is going to be a national rethink of whether it is OK for the midwest to wreck the air shed of the northeast. This is something mercifully you probably will not have a dog in the fight so much so you can be an honest broker, but I think that is going to be a big cat fight down the road. And you could run a whole lot of these older plants flat out and make the air dirty in the West and that is probably a loser. I mean, there is maybe some temptation to do that. I think on reflection we probably will end up not doing that.

So that there is some risk, if you do not have a service territory where you can sell to a native load and then if you have any excess to sell it around in the marketplace, that is kind of the old system or where we are right now. But I think it is going to be a lot dicier. We have had fairly low cost capital in this benevolent regulated world.

But in the new world that is coming up, it is the cost of capital, I suspect, that is going to go up because these plants are going to be risky and you do not have a captive customer base that can absorb some of that risk and sort of an assured cost recovery.

So I am not sure that that does not have a fair set of risks associated with it, but on balance, and I think Gregory and I would agree on this, that the benefits of competition in generation are probably out there and it is certainly not a natural monopoly any more, which is a reason to do what we are all doing at a various rate of speed, but I naturally would be interested in what others think about the looming risks, but this is not just going to be cheap power forever for everybody, I do not think.

Mr. DOOLITTLE. We are going to get to Mr. Conlon here in a minute, but let me—you seem to imply that because of the increased risks that we would see fewer new transmission and perhaps generating systems built. Is that correct?

Mr. JENNINGS. I think in the short run, we are going to probably—transmission is going to get harder to do. In the old days, you had eminent domain and the local dog in the fight, the big utilities that had the ability to get things done with an interest in making sure that it got done.

Now, an incumbent utility already has the ability to serve its own customer base and a new line may be seen as somebody's ability to bring in competitive power from some place else.

Now, what I just said is diminished somewhat by the fact that there is going to be a lot of open network architecture on this, open access, but still there is the existing architecture. There are going to be some power plants that are here and they have a line to the load center and that is going to be basically the plant that gets output that gets sold into a marketplace. So there is a lot of residual market power just from the architecture of the old system.

Mr. DOOLITTLE. Mr. Conlon?

Mr. CONLON. I apologize for getting into a restructuring discussion, but that is where we have moved to and I think in due respect to what we are trying to do here in California. I think the driving force behind this is one technology, that the cost of generating electricity with the gas turbine technology has got to a point where the cost of building new generation is much less than anything that we are operating today, so there is a tremendous opportunity that the large industrial customers and the small ones that have meaningful loads want to take advantage of.

They want that new technology just like 10 years ago they wanted the low price gas when gas was available but you could not get it inside the State. So 10 years ago we went through this in the gas industry and we have the lowest gas prices in the United States today. So we are trying to go through it in electricity by taking the generation market and only the generation market and deregulating it to a point where you have a viable competitive market and I think that most of the excess capacity today is plants that are not as—you know, like 10,000 heat rate and above compared to new plants of 7000 so they are 30 percent less efficient in using fuel. That is probably a third of the generation in Southern California are those kind of plants.

I was at a meeting just recently where somebody said there was 18,000 megawatts out of 60,000 megawatts in Southern California and Arizona that have heat rates over 10,000 BTU, which is very inefficient.

So with new technology and a competitive market, eventually once you get the initial—everybody is going to be bidding their variable cost and once that ends and we are into a level of bidding where you cannot just bid your variable cost, that new technology will come in, we will get new investment in California and the market will flourish with new investment of these efficient generators. And big customers will get direct access contracts for a new generator. I mean, that is the name of the game.

And slowly the market will flourish and hopefully the economy will flourish with it. So we are trying to use a market-based concept for just the generation. The transmission is still regulated, but it has to be done on an independent basis. The distribution is still regulated on a cost-of-service basis or a variation thereof, so it is just—and as far as the people at Idaho, I wish I had their problem. I mean, they have the resources—I mean, they get the money. I mean, they can share it with their residential ratepayers and have zero bills. I mean, to sell the money into the pool and share that with the ratepayer, I mean, they could reduce their rates even further in Idaho with any kind of sharing arrangements between the residential ratepayer and the stockholder.

So, I mean, it is an opportunity to use their excess supplies to sell into a market and maximize the value that they can share with the residential ratepayers and everybody wins in Idaho. I mean, I wish I had their problem.

Mr. JENNINGS. I do have a different perspective here and not to sort of request equal time on everything and we are a little——

Mr. DOOLITTLE. This hearing is going to last a long time, but go ahead. That is all right. I am interested.

Mr. JENNINGS. I certainly agree with President Conlon that the gas turbine technology is the driver. But is also predicated on the perception and the reality of low gas prices and there are a lot of factors in here. There is an oversubscription of the hydro base and you are seeing a problem worrying about what some have termed a few fish. Well, if you spend a little time in the Pacific Northwest and they are pretty serious about the runs of salmon. It is part of their culture and that is their patrimony and they want to preserve that.

In Idaho, there is not going to be a whole new set of dams. I mean, that resource is already pretty well subscribed. Which takes me to the point, I think, we should not lose sight of the role of technology, but we also ought to not lose sight of the importance of having a portfolio of resources.

That is why I think California is to be commended and has done a good job in maintaining their commitments to renewable energy and why others of us who have been a little late, even with the great solar resource coming into this with a solar portfolio standard for a State like Arizona, and there is really a good reason and I would like to—it does not often make its way into the discussion, but I hope that you take this, if it is a good insight, take it back to Congress.

For whatever reasons the low-lying countries and cities of the world take the threat of global warming a lot more seriously or climate change than perhaps people at 5000 feet, and they may have a fair amount of political pressure and we do not know where greenhouse science is taking us, but we know that there is a risk out there and it is a fairly large risk, we just do not know how likely the risk will be to come due.

So if you need to back away from carbon fuels, that puts you right into natural gas, which any time one fuel gets in essence a monopoly you can extract monopoly rents, which is why the value of having new technologies to do research and development to be able to hedge those long-term risks is probably a pretty good bet to place. And to the degree that everybody is thinking right now about low price, they ought to be thinking about how you hedge long-terms risks as well as get the benefit of low price now, but to make sure that you can keep it as low and environmentally sustainable over the long haul as well.

Once a fuel gets a monopoly, it is going to do what you would expect it to do, charge monopoly rents.

Mr. CONLON. I would agree with that and I would just add that in California we have committed for the next 5 years that we will maintain our renewables as a percentage of the total load as what we have had in the last 5 years, so we are not in any way taking away from the portfolio diversity of renewables.

Mr. DOOLITTLE. I want to switch subjects here.

Now, do you regulate—do your public utilities commissions have anything to do with maintenance of rights-of-way and herbicide use and that kind of thing? Or is that strictly up to the utilities themselves?

Mr. CONLON. In fact, we just published yesterday, we had a commission meeting yesterday, and we published standards to be commented on by the parties for distribution assets, otherwise the poles, wires and transformers in the neighborhood.

We put out standards that we will get comments on and hopefully we will act on within a short period of time to at least on the distribution side—but to my knowledge, we have not discussed the herbicide issue at all and maybe we should because we are right at that point of considering what should and should not be done.

Now, in my testimony I mentioned that I think that on the higher voltages that we need to get more involved because of the global risk for the entire State based on the August 10th event. As far as I am concerned, our commission staff focus will be at the higher levels, but we will set standards and do compliance work at the distribution level also. But herbicides I think you will have to ask these two gentlemen what their experience has been.

Mr. DOOLITTLE. OK.

Mr. JENNINGS. Happily, we have no relationship to herbicides that I know of. Our cactus grow an inch a year and we had seven inches of water, rainwater, in the higher country, where much of the transmission stuff is. The sagebrush has a hard time growing, it is pretty windswept and pretty dry, so this issue has just never come up.

Mr. DOOLITTLE. OK. You indicated, Mr. Jennings, that Idaho or in Boise, I guess it was Idaho Power that let Boise have an outage in order to save the rest?

Mr. JENNINGS. Yes. That is as I understand it and, again, others perhaps are better positioned to comment on it than I am. The point of that was that in this sort of fraternity network that we have now where valor and decency is highly rewarded, perhaps you get a CEO plaque or something at the EEI meeting, inducted into the hall of fame or whatever, but you would be considered to be a chump in a competitive marketplace if you cut your own power to your own communities to keep the grid from unraveling, although, as I understand it, their quick action to dump Boise helped it from then everything going black.

My understanding of the situation is if you can retain some amount of generation and load and try to have something like a flywheel up in balance it is much easier than to have the whole system go down and then try to build it back slowly in increments over a couple of days.

Mr. DOOLITTLE. Is that what happened, Mr. Hardy? Idaho voluntarily did that to itself?

Mr. HARDY. Essentially, yes. They had a repeat on July 3rd of similar sorts of circumstances that had occurred that had precipitated the widespread outage on July 2nd. Their dispatchers recognized it, intervened manually, put Boise in the dark, but that probably was the difference between having yet a second cascading outage on July 3rd which would have paralleled the one on July 2nd.

And the difference there would be what we had on July 2nd was you had total voltage collapse in Idaho. No system is designed to withstand total voltage collapse in an adjacent system.

They put the Boise area in the dark, but they stabilized the rest of their system, so the outage did not spread into the Bonneville system and hence did not separate the intertie like it did on July 2nd.

And that is an example of the kind of islanding schemes that Mr. Bonsall was referring to and that the WSCC report references in other parts of its recommendation. It is not just preventing the initial cause of the outage. While prevention is the most important part, given that you cannot give 100 percent assurance that you will never have circumstances leading to another outage, you also have to take actions that mitigate the extent of the outage. Such actions typically involve load tripping and generation tripping, either automatic or manual, to mitigate the extent of the outage.

Mr. DOOLITTLE. So in the Boise example, they islanded themselves, is that right?

Mr. HARDY. Essentially. Yes.

Mr. DOOLITTLE. Is that a term we could find in the dictionary? Apparently it is a fairly common concept.

Mr. JENNINGS. Probably after August 10th editions.

Mr. HARDY. It is a common concept in NERC and all the reliability councils. I mean, that is what the system is designed to do. And how well you do it determines what the extent of the outage is and how long it takes you to restore.

Mr. DOOLITTLE. We had tried in setting up the witnesses to get some direct testimony as to the impacts when you do have an outage, but let me ask any of the three of you or all three if you care to, to comment, particularly the two heads of the public utilities commissions, what impacts did you see in your States as a result of the August 10th outage, both in terms of the impact on any given business or the overall perception, the business climate.

Can you comment on that? I understand this has a tremendous impact, say, on the chip manufacturing industry, for example.

Mr. CONLON. Well, I think the two utilities should comment in more detail but generally I think in California we lost over four million customers on Saturday and it was into the night before they got restored. Probably I think by midnight they got most of it restored. Fortunately, it was on a Saturday, so we did not, I do not think, have the chip problem as much as we would have had if it would have been on Monday or Tuesday.

Mr. DOOLITTLE. It would have been much greater if it had been during the business week?

Mr. CONLON. You should confirm this with the utilities, but I think that is right. We estimate tens of millions as a result of the outage. And, you know, I was startled, as I think you were, with the analogy of the six fish for tens of millions of dollars but, you know, it is just—it is difficult to make those judgments and what your interests are, but it was tough.

At one point, I found out after the fact, and I am an accountant by training and I am learning a little bit more about electrical engineering, and I guess there is a way to run The Dalles units without having water going through them by treating them as a motor or somehow, and, again, my colleagues from the utilities behind me can explain how it works. But I think if that would have been done, and I understand it is not that expensive to convert those units to be able to do that, if those units had been running without water going through them, just at the system voltage as a motor, in other words, you would be using electricity to drive those turbines to run, but if they had been spinning, then they could immediately have activated them to help this situation. So that would be another remedial action that could be taken by the Corps and the Bureau that would be very helpful for the voltage control for the intertie.

Mr. DOOLITTLE. Is that what spinning reserve is?

Mr. CONLON. Well, I do not think so. I think it is more than that and I think we should let the two gentlemen who are more knowledgeable——

Mr. DOOLITTLE. OK. All right. We are going to have lots of fun things for them to talk about.

Did you want to comment in terms of any——

Mr. JENNINGS. Again, it was a blessing that it happened when it did. It does not take much imagination to think, gee, if this had been at 4 on an afternoon on a Friday and you are trapped in an elevator for 4 or 5 hours, I suppose a lot of buildings have back up power, or it happened on a Saturday night when the kids were all out liquored up and the lights went out and the cops were spread thin, you know, it could have happened at a much worse time. The fact that it happened and everybody is now so focused on this before we move into a situation that may destabilize the situation as opposed to correct it, it was a benefit that it happened when it did.

Yes. There would be a huge loss of productivity. What I found is that our utilities were very quick to recognize the magnitude, the importance of it. How people would have freezers full of food. They were buying dry ice from all over, way out of the region, and flying it in and letting people know that they could get dry ice to protect stuff. So it was a nice dry run in the sense to see how committed they were to customers and how quickly they could crisis manage I think stimulated a lot of thinking. But it really happened at a time that was pretty favorable and there was not the loss of the manufacturing base, a day or a week's production or whatever, you are in process and you go down and you have lost millions and millions of dollars. So we really bypassed a whole lot of that.

There were a few situations where there were health situations, but for the most part there was just a handful of economic consequences.

We did get an awful lot of calls, I have been trying to send them up to Randy and I suspect that there is a big thick file of people who either were impacted by computers or refrigerators or air conditioning units and so forth that were fried or people had old ones and claimed that they lost things, but we did get quite a few calls on that and some people were pretty irate. And, again, it happened at a time of day where you would probably have the least amount of that kind of—do people really surf the Internet on a Saturday afternoon? I do not know.

Mr. DOOLITTLE. Knowing what you know about the August 10th incident, let me address this to the two PUC people, is it likely that had the utilities under your jurisdiction been the ones who were— pretend they were BPA but they were under your jurisdiction, the same set of circumstances, is it likely that they would have been sanctioned or not? And if so, what would the sanctions have been?

Mr. JENNINGS. It depends on whether it was the first time or the second time.

Mr. DOOLITTLE. Well, what about with the history we have where there were at least two prior incidents about a month before, raising the possibility of such things in the future, which then ultimately happened on August 10th?

Mr. JENNINGS. You almost have to answer hypothetically because right now we have a voluntary system in place and you play with the rules that are in place, but I think it is a clear case of there need to be sanctions for people who do not meet their obligation because it screws it all up for everybody else. So one participant, whether small or large, could do something that would have a cascading effect and that is unacceptable.

I think the old system has worked marvelously well. It did not work in this situation. It would work much less well with a larger number of players and with people who are doing bilateral contracts as well as just a huge increase in the number of transactions and players making transactions.

Mr. CONLON. You know, we just fined PG&E a half a million dollars yesterday for not meeting their call center, their telephone call center up in Sacramento.

Mr. DOOLITTLE. For not doing what with the call center?

Mr. CONLON. Not meeting the response time of 20 seconds for their calls. We have pending reviews of their storm for last December on their distribution system and how it behaved and I do not know what we are going to do and it takes three votes to get anything done, but that is yet to come before us. But I think that it would be difficult to take sanctions if you did not have standards, so I think the first thing that we probably would do was do what we are doing, is getting standards established and then I think probably the first time out of the box we would probably not have been so anxious to have sanctions.

There has been a lot of political pressure to do that, but I think that until we have standards that we can judge them by as to whether it was reasonable or not or prudent or not, that it would have been difficult to do something. But I would say the second time, once we get standards established and then there are violations, then I think there would be sanctions and the main sanctions would be fines and penalties. And we fined Pacific Bell $15 million for not applying the cash properly after we had told them at least 10 times to do it.

So I think that, you know, you would have to judge the sanctions with the violation, but I think it would have been tough to do anything right out of the box. But we get the standards established— you know, one of the suggestions is that we have standard fines and sanctions depending upon what the violation is so that the WSCC could impose them if they were automatic. Otherwise, if you violated this, it is going to cost you $1 million, if you violated that, it is going to cost you $10 million. And if you have some muscle in those sanctions the attention to the detail would be a lot greater.

So that is really—I do not think we would have fined them anything. I would not have voted for it unless I felt it was clearly imprudent or unreasonable what they did, unless there were clear standards and they violated them.

Mr. DOOLITTLE. And I am just trying to assess how commonplace these are. I gather that 500,000-volt lines are not that commonplace. I mean, they are the biggest lines, I guess in California, anyway, right, that we have?

Mr. HARDY. I think so.

Mr. DOOLITTLE. I am just—this criteria of WSCC and it is in this report they gave, their procedure for coordination of scheduled outages, notification of forced outages, on pages 14 and 15, where it says, "Each WSCC member system which owns or operates a key generation or transmission element scheduled to be removed from service or which has been forced out of service is responsible for notifying the other WSCC members via the WSCC communications system of the facility outage. Key facilities are those which are considered important to interconnected system operation by the system which owns the facilities. Key facilities generally include" and then it skips down and cites the relevant paragraph, three, "transmission operated at 230 kilovolts and higher that can significantly affect interarea system operation."

Maybe simply as a layman it seems to me that a 500,000-volt line that goes down would certainly be a key facility, would it not?

Mr. HARDY. Can I speak to that, Mr. Chairman?

Mr. DOOLITTLE. Yes. Yes. Jump in.

Mr. HARDY. I think that there is some confusion here. As the standard that you just read indicates, what is a key facility is in fact determined by the transmission owner. The first two lines that went out before we got the Keeler-Allston were 500 kv lines but they are lightly loaded. We did not, knowing what we knew at the time, think those met the definition of key facilities. In retrospect, we were probably wrong, even though that has not been firmly established yet, given that we have not run the studies. Keeler-Allston clearly was.

What we have moved to do with the operating agreement that I described with Pacific Gas and with Edison is to remove that discretionary judgment. It is an attempt to reach the standard Commissioner Conlon talked about so that it is clear, which facilities—line by line, transformer by transformer—will require notification of adjacent utilities in the event of an outage.

In retrospect, it would have been nice to have that earlier and at least that would have afforded Pacific Gas and Edison the opportunity to potentially take corrective actions which may or may not have had an effect. Prior to August 10, and you had an awful lot that was in the judgment of the dispatchers relative to what happened and now we have moved to correct that.

Mr. DOOLITTLE. OK. And that is in fact corrected, I guess, internally within BPA, at least.

Mr. HARDY. I think that element of discretion is removed not just for us, but for Pacific Gas and Edison as well. My guess is when we finally get through with this we will have such an understanding with all the transmission owners; that is we will have a similar list of key facilities that they will be required to notify other owners about when there is an outage, either planned or unplanned.

Mr. DOOLITTLE. Now, is WAPA involved in this?

Mr. HARDY. Yes. WAPA would presumptively be involved in it if it is expanded to the other owners.

Mr. DOOLITTLE. OK. Well, I do not think I have any other questions. This has been a good panel, too. I appreciate your testimony and we may have—I should have mentioned to the first panel but I will mention it now, all these panels, there may be further questions that we will have and we will submit them in writing. We urge you to try and get back quickly with a response.

Mr. CONLON. I appreciate the honor.

Mr. DOOLITTLE. Thank you very much for attending.

[Witnesses excused.]

Mr. DOOLITTLE. With that, we will call up the third and final panel.

I think we are waiting for our third panelist, so just have a seat and we will ask you to take the oath when he is here. If I may ask you to rise and take the oath. Raise your right hands.

[Witnesses sworn.]

Mr. DOOLITTLE. Let the record reflect each responded and replied in the affirmative.

We are pleased to have you here and we are looking forward to your testimony.

We have on this panel E. James Macias, Vice President and General Manager, Electric Transmission Business Unit, Pacific Gas and Electric Company; Marcie L. Edwards, Manager, Bulk Power Operations and Maintenance, Los Angeles Department of Water and Power; and Vikram S. Budhraja, Senior Vice President, Southern California Edison.

Thank you for being here.

Mr. Macias, please begin with your testimony.

STATEMENT OF E. JAMES MACIAS, VICE PRESIDENT AND GENERAL MANAGER, ELECTRIC TRANSMISSION BUSINESS UNIT, PACIFIC GAS & ELECTRIC COMPANY

Mr. MACIAS. Thank you, Mr. Chairman. For the record, I would like to state that I am not happy with the outage event that occurred and I do not consider it a blessing. Nevertheless, there are a number of things we can learn from it and actions we can take.

On August 10th of this year, the Western grid in the United States suffered its second major disturbance in 2 months, its third in 14 months. In our opinion, the cause of both events was a lack of effective voltage management by exporting utilities in the regions. This lack of adequate voltage management caused a series of line and equipment failures to escalate into massive voltage collapse and grid instability in the Northwest.

These instabilities in turn led to widespread customer load shedding throughout the Western United States as other utilities' security systems operated automatically to stabilize the grid.

Economic trends in the industry are driving usage of the grid to a greater extent than ever before. These forces are pushing many generators to maximize electrical output for sale to distant markets and retailers to reach further out in search of low cost supplies. Recent enhancements to the regional grid and open access regulation now make this access to long distance supplies easier. These conditions are increasing regional flows to higher levels and different patterns than we have ever experienced before. This trend will continue.

My analogy is driving on a winding road. With ideal weather conditions and at speeds well below the maximum speed limit, the driver feels safe and complacent even if they have a poor suspension and bald and over-inflated tires. However, as weather conditions worsen and they try to drive at the safe speed limit, all of a sudden they can find themselves in a very bad situation that can lead to disastrous results. I think that is a very good analogy of what we experienced.

On August 10th, less than ideal operating conditions existed. Critical generating and switchyard voltage support equipment was either unavailable or experiencing operating problems. System operators failed to recognize early warning signs of voltage instability in their control areas. Further failure of unreliable equipment led to these disastrous results.

Why is voltage management so important? Voltage is the back pressure that allows electricity to flow across the wires. To safely control the flow of electricity across the wire network, voltage has to be carefully managed at the generating source, at the consumption end and in steps in between. The longer the distance between the generating source and the consumption end makes it technically more difficult to control this voltage at the appropriate levels.

What corrective actions can be taken? You have heard of some of them that were immediately taken. The first step is to restrict the flow of energy that can flow across the California-Oregon border until we are satisfied that effective voltage management controls are in place, the procedures are there, operators are trained, they are monitored and they are enforced.

The second step was the communication that was discussed earlier. That is very important. Taking away the ambiguity and having clear communications will allow utilities like ourselves to take actions to better insulate our customers from operations and disturbances that are occurring outside our border.

I think it is very important that the WSCC proceed with this review of voltage procedures and training from a top to bottom review. I am confident the procedures and training will be enhanced.

WSCC will determine compliance with all WSCC operating procedures, especially voltage management. This has already begun.

And WSCC is working to establish four regional security centers, one of which will be PG&E, to exchange data, monitor system conditions for potential reliability problems and coordinating system restoration.

In a further long-term correction, the proposal that California is proceeding with I think will have dramatic improvements on system reliability. The restructuring proposal before the Federal Energy Regulatory Commission would separate and isolate reliable grid operations from the economic drivers of the competitive supply market. The independent system operator will be solely responsible for reliable grid operations and will have no economic interests in the market. Organizational separation of the ISO from generation markets and other supply coordinators will ensure this reliability-only focus.

ISO regional control would replace numerous utility-specific control points. Today's regional control is a patchwork of dozens of local utilities coordinating with each other. Regional ISOs are being considered to better monitor system conditions.

And the third are the mandatory protocols with financial settlements for non-compliance.

I think those are the critical steps that need to continue. The discussion and debate on industry restructuring I think is in some part beside the point. These outages and these occurrences have occurred before any restructuring events have taken place.

Mr. Chairman, that concludes my testimony.

[The prepared statement of Mr. Macias may be found at the end of the hearing.]

Mr. DOOLITTLE. Thank you very much.

Ms. Edwards is recognized for her testimony.

STATEMENT OF MARCIE L. EDWARDS, MANAGER, BULK POWER OPERATIONS AND MAINTENANCE, LOS ANGELES DEPARTMENT OF WATER AND POWER

Ms. EDWARDS. Mr. Chairman, I want to thank you for the opportunity to share a Los Angeles perspective of the August 10th event, though I must comment at this point that much of my testimony will be an echo of much of what you have heard already today.

On August 10th, Los Angeles Department of Water and Power, like the rest of our neighboring utilities in the southwest, was significantly impacted by an electrical disturbance which originated a thousand miles away. We intentionally disconnected nearly 600,000 customers to help stabilize the power system during the first 15 minutes of the disturbance, while 11 of our electrical generating units were automatically disconnected from the system.

Our ongoing concern for the reliability of the interconnected transmission system was subsequently demonstrated by our active participation in the investigation of this disturbance.

A considerable number of technical and operational factors underlie this complex disturbance. In reviewing these factors, we believe there are four primary issues that lie behind the events of August 10th.

First, the disturbance reminds us we are part of a single interconnected power supply and one that is shrinking in commercial distance as competition suggests more and more consumers may be purchasing their energy from places further away. As the commercial distance across the interconnected system shrinks, it will be imperative for all the entities deriving benefit from the interconnected system to join utilities in taking prudent, consistent steps to ensure power system reliability. We cannot assume that the operational practices of what's been called a monopolistic past will suffice in a competitive future.

The voluntary reliability mechanisms of the past 30 years have served this industry very well. However, we cannot assume that reliability standards will continue to be enforced in a competitive environment and we should review the applicability of commercial sanctions and/or penalties.

Second, while the coming competition is moving the industry away from its once held position of freely sharing financial information, competition will be simultaneously increasing the pressure on studying and operating the system more aggressively and moving the industry toward a need to share more technical and operational information and to do so in a much better way.

Significant to the August 10th investigation was the question of whether the Bonneville Power Administration should have made wider notification of transmission outages in their system occurring just before the disturbance.

While the technical jury is still out on the impact these outages had on the initiation and severity of the disturbance, future reliable system operation will depend highly on companies sharing operational information such as voltage levels, real and reactive power flows and lines out of service in a timely fashion.

Regional security centers like the type that Jim mentioned and the soon to be implemented California independent system operator will play major roles in sharing the operational information.

Third, aggressive energy marketing, heretofore rarely seen in this industry, places additional stress on the existing transmission system. To the consumer's benefit, aggressive energy marketing is here to stay and so the burden falls to the industry to increase its efforts to effectively monitor, study and predict the State of the power system.

As the industry relies more and more on operating the existing system to its full capacity, the reliability of the system will increasingly depend on our ability to accurately model, simulate and control the flow of electric energy.

Again, the WSCC's progress toward establishing regional security centers to monitor the flow of energy, plus California's push to establish an independent system operator to control the State's transmission grid speak to the requirement for more comprehensive and timely predictive analysis.

Fourth and finally, while it is true that the power provided by electric utilities has an impact on society and its environment, it is increasingly true that societal and environmental forces also have an impact on an electric utility's ability to generate and deliver power reliably and economically.

On August 10th, as you have heard, the operations at The Dalles reduced the power support that this station provided to the transmission system. Electric utilities must not shirk their responsibility to work within environmental constraints which are put in place to preserve a common good. Nevertheless, it is worth pointing out that reliable electric power is in itself a common good worthy of equal consideration in the public debate.

In summary, Mr. Chairman, we believe the major lessons to be learned from this disturbance are the need for old assumptions to be put aside and for all of the parties deriving benefit from the interconnected transmission grid to work together to ensure the continued high degree of reliability we previously enjoyed; the need to increase the sharing of technical information, even as there is a competition directed move away from sharing commercial information; the need to more carefully and completely study a system which is being operated as never before, and the need to balance the impacts of external constraints with the need for reliable economic electric energy.

Thank you, Mr. Chairman, for this opportunity to speak to these issues. This concludes my testimony. However, in response to an earlier inquiry, 500 kv is actually two of these bundled and then you would see three strands going in between the transmission towers, and we will have this for you, if you would like to look at it, sir.

[The prepared statement of Ms. Edwards may be found at the end of the hearing.]

Mr. DOOLITTLE. Thank you very much.

Mr. Budhraja, you are recognized, sir.

STATEMENT OF VIKRAM S. BUDHRAJA, SENIOR VICE PRESIDENT, SOUTHERN CALIFORNIA EDISON

Mr. BUDHRAJA. Thank you very much, Mr. Chairman, for the opportunity to appear before this Committee. You have already by now heard the details of the outage and I am going to briefly focus my remarks on the impact on Edison, steps to be taken to avoid such events in the future and, most importantly, in my judgment, focusing on how to manage reliability in the emerging competitive market.

First, let me say that for Edison reliability is very important. We are committed to providing reliable service to our customers and this involves focusing on all of the elements that constitute reliability, including maintenance, design, planning, training and operation of our system.

As you know, the August 10th outage and the previous July 2nd outage, both of which originated in the Northwest, were attributed in part to deficiencies in tree trimming. Also on August 10th, five major transmission lines went out of service over a period of 1 hour and 42 minutes without corrective action.

At Edison, we play a lot of attention to trimming our trees and we have gone back over the last 5 years in our records and we have not had even one outage attributed to deficiencies in tree trimming for our bulk power system. Of course, that is not good enough. We need to maintain this record in the future.

With respect to corrective actions, our operators have strict instructions that in the event of any doubt about reliability due to equipment outages or operating conditions, take corrective action first, assure reliable operation to our customers and then evaluate the state of the system. In terms of what Mr. Macias said, slow down your speed on a winding road.

The August 10th outage had a significant impact on our customers. In Southern California, we have 4 million customers affecting a population of 10 million people. On that day, 1.8 million customers lost power, almost 40 percent of our system. Our service restoration started immediately and within approximately 3 hours we had a substantial portion of our system back in service.

Our system behaved well. We started 19 power plants. Most of them were on by later that evening and continued to operate in the ensuing days to help out not only service to our customers, but also to help PG&E and other neighboring utilities in the West because of the heat wave.

The August 10th outage should not have happened. We have taken steps within WSCC, and I must congratulate Randy Hardy and BPA's proactive approach in fixing the problems that were identified. I think that has been very good. And we need to make sure that these efforts continue.

In addition to paying attention to tree trimming or vegetation management, maintenance and review of local voltage supply, there are several other preventative measures that have been instituted among the utilities in WSCC. These include, for example, requirements to communicate information on status of major equipment outages to other utilities; in the event of outage of any equipment, to reduce system usage to safe levels; and, in the event of any uncertainty regarding the safe and reliable operation of the system, to take corrective action first and make engineering evaluations later.

These items focus on good operating practices which you must do. Looking forward as we transition to competitive markets, it is also important to focus on rules to manage reliability consistent with a competitive marketplace. In a competitive market, the current voluntary system is unlikely to be adequate. The vertically integrated structure of electric utilities is transitioning to a disaggregated structure with functional separation of the generation, transmission, distribution, marketing and operating functions.

In this new environment, with many more players, we need mandatory reliability management protocols, compliance monitoring and mandatory enforcement with consequences for lack of compliance. The key building blocks for such a system would include: focusing reliability management responsibility; industry should take the leadership to overhaul the existing framework to strengthen the role of the North American Electric Reliability Council and the regional reliability councils; volunteerism must be replaced with mandatory reliability protocols; all market participants must accept an obligation to comply with reliability protocols. It is not just enough to focus on utilities, but all market participants.

Formation of independent system operators, as we have heard, should be encouraged as this will help to unify control areas, enhance coordination, and implement mandatory protocols.

NERC and regional reliability councils should have standard setting, monitoring, enforcement and sanction capability.

FERC should support mandatory reliability protocols and require an obligation to comply as part of an open access tariff and power marketing licenses.

The costs of reliability must be fully recoverable and paid for by all consumers and market participants.

And, finally, the ISOs and control area operators should be members of reliability councils.

There has been some debate on the role of ISOs and whether they will help in reliability management. Let me suggest that in my judgment they will because they will establish focused responsibility for reliability management, unified control areas, simplified communications and coordination, help in implementing mandatory protocols and, most importantly, separate the commercial and reliability functions.

The industry has to take a leadership role to make this happen and some of this is already happening through the leadership at NERC and at Edison Electric Institute. I also believe that the Federal Energy Regulatory Commission can play a very important role by supporting industry efforts to strengthen the reliability focus requiring the use of mandatory protocols for reliability in ISOs and including mandatory reliability compliance as part of open access tariffs and power marketing licenses.

However, this alone may not be enough. You had asked a question earlier regarding the role of PMAs and let me address that directly. In this country, about 30 percent of the power systems are not within the jurisdiction of FERC. This includes, for example, Federal power marketing agencies such as Bonneville.

I believe it is very important for BPA and WAPA to be fully committed to join an ISO, to separate the commercial and reliability management functions. We need a level playing field with the same rules for all players. Integrating BPA, WAPA and other power marketing agencies' transmission systems with ISOs and recognizing that the ISOs will be under the regulatory jurisdiction of FERC, this would be an important step to unifying the electric power systems in the West as well as in the rest of the country and should help in dealing with many of the issues in the emerging competitive marketplace.

In closing, let me just emphasize that reliability need not be sacrificed as we transition to a competitive marketplace. In fact, it can be strengthened. However, we cannot take reliability for granted. We have to pay attention to the creation of ISOs because they will go a long way toward focusing responsibility for reliability management and imposing mandatory reliability protocols.

In California, we are moving in this direction and I urge you to support such a transition.

Thank you.

Mr. DOOLITTLE. Thank you.

Mr. Macias, could you describe the secondary impacts on PG&E facilities from the outage? We have heard about Diablo Canyon, both units, I guess, going down, and I believe there were others as well.

Mr. MACIAS. The operational impact and the customer impact is when the instability hit and the voltage collapse hit, the wire system, the grid system, actually sees a physical impact. It is like a water hammer hitting the system. And the protection devices on the plants feel that and open up and separate the plants from this water hammer to protect it from being damaged. That is what led to this widespread dropping of plants.

As this instability and collapse spread from the Northwest in a parallel path through the Western grid, those plants closer to the origin of it saw a bigger impact. That is why you saw ones on both the eastern side and the western side were impacted.

Both our Diablo Canyon plants went down. Well, nine of our plants went down. A non-nuclear plant you can bring up even if it has damage. We had a number of plants that blew steam tubes but you can still operate them, limp them along. A nuclear power plant you cannot do that.

When the plant tripped and it separates, the steam valves lift. Now, we have about five steam valves per unit. One of the valves lifted literally a nanosecond slower than what it was supposed to by the textbooks. We have to do a thorough review of the plant top to bottom as well as we had to identify why did that safety valve not operate the nanosecond it did not. Is that a generic problem with others? And it took us several days before we could adequately operate, bring the plant back on line. Forty percent of our customers lost power. The longest was out as many as 9 hours. We have estimated the direct cost to us, cash cost to PG&E, to be about $40 million.

I am not an economist on what the economic impact is to our customers' economy, but just anecdotally, the stories you hear from customers of the impact, it is probably ten times that amount to the economy, so the economic impact is quite significant. A lot of our customers operate 24 hours a day, 7 days a week, in continuous operations. They cannot drop off their mass productions, be it chip productions or gas manufacturing or other mass production facilities, so we have significant impact, even if it occurs on a weekend or during the night.

Mr. DOOLITTLE. So just the impact directly to PG&E was $40 million.

Mr. MACIAS. Yes.

Mr. DOOLITTLE. And you estimate $400 million to your customers.

Mr. MACIAS. Could be. It is probably in the hundreds of millions to the California economy, at least in our service territory. And the loss, the stories you hear of lost production, lost downtime, for customers.

Mr. DOOLITTLE. Let me ask our other two witnesses if you can give us the same estimates for your service areas.

Ms. EDWARDS. The financial estimates for the department were probably somewhat under a million, though the magnifier for the community impact is probably equivalent to what Jim had mentioned.

Interestingly enough, though, in addition to the economic impacts, there are a lot of societal impacts that occur on these type of outages. Due to the low voltage, we lost some of the waste treatment facilities at Hyperion and there was partially treated sewage that went into the bay. There were some problems with resetting traffic lights. We had hundreds of traffic lights out across the Los Angeles area which caused snarls for hours. So there are multiple areas in which these type of occurrences can impact us.

Mr. DOOLITTLE. Mr. Budhraja?

Mr. BUDHRAJA. Yes. As I indicated, 1.8 million customers were impacted, which is about 40 percent of our system. It is very difficult to estimate exactly the economic loss due to production and the disruption that took place on the Edison system. The financial impact of the experience was not even close to what Mr. Macias did. I think PG&E was impacted more being closer to the trigger event, but I would venture to say that for us it would be in the single digit millions of dollars.

Mr. DOOLITTLE. And much of your cost, Mr. Macias, was because of the nuclear reactors going down?

Mr. MACIAS. That was by far the greatest one we have had. We had transformers that were damaged on the disturbance.

Mr. DOOLITTLE. Let me ask, you have heard a little bit of the discussion over the testing of some of the generating equipment, I believe it was at the McNary Dam. How does your testing—you have dams, do you not?

Mr. MACIAS. Yes.

Mr. DOOLITTLE. How does your testing policy compare with what you understand to be the case in BPA and the Corps?

Mr. MACIAS. I am not that familiar with BPA or the Corps' operation, but I can describe our operations.

Mr. DOOLITTLE. Sure. Describe yours.

Mr. MACIAS. Hydroelectric operations in California are really no different than anywhere else. You have safety, you have environmental, you have recreation usage that you have to balance as well as economic operations, so it is a complicated operation. Your hydroelectric resources are your most valuable, your most economic. You try to maximize their operations during the highest cost hours to maximize the value of them. Because they are so valuable, you have real clear availability standards that your operating organization operates to and you have clear performance measures.

Our operating availability of our hydro facilities is in the above 90 percent range, with the majority of them above 95 percent range. Hydroelectric facilities really are not that complicated. They are less complicated than steam plants as far as complexity.

Mr. DOOLITTLE. This is the availability figure you are giving us?

Mr. MACIAS. Yes.

Mr. DOOLITTLE. And you said 90 to 95?

Mr. MACIAS. Correct.

Mr. DOOLITTLE. So that is substantially higher than the Corps of Engineers.

Mr. MACIAS. Than the numbers I heard earlier. Yes.

Mr. DOOLITTLE. OK.

Mr. MACIAS. The operating equipment is no different than automobile vehicle. If you have a vehicle and you take very good care of it and you do your routine maintenance, you are religious about changing the oil and you replace parts as you go, as they wear out, they can continue to operate very effectively for long periods of time.

Mr. DOOLITTLE. Or you can kind of run them into the ground and then it is more expensive.

Mr. MACIAS. Correct.

Mr. DOOLITTLE. Ms. Edwards, give us this information for your area.

Ms. EDWARDS. I would suggest, sir, that the issue surrounding McNary, while involved in the utilization of a hydroelectric facility as a whole, really targeted to a large extent on the voltage support components provided by those individual facilities, what they call the excitation systems or power stabilizer systems, and the effect that that had. Our response was what the Corps of Engineers was going through in greater detail earlier.

It did send, I think, a wake-up signal to many in the industry to review their own power system stabilizers; their own voltage support equipment on their generating facilities. And I think that is really more the issue involving McNary itself. When those 13 units tripped as a result, the exacerbating effect, then, that they had by removal of that support, how much further that caused the collapse, if in fact it contributed much more to the downfall.

Mr. DOOLITTLE. I guess we had heard the testimony that there was a lack of proper tuning of some of that equipment and they did not discover that because they did not—it sounded like they did not routinely perform that kind of a test in a dynamic state. I just wondered, do you——

Ms. EDWARDS. I think since that point, in response to WSCC, particular to our own utility, the report came in fairly recent, on October 25th, that we reviewed the status of the power system stabilizers across all of the generating units in our system, including the hydro plants, and those that meet the WSCC criteria have been tested and found to operate within the established parameters.

We reviewed the testing schedules to make sure we are on track. We tested most recently in 1992. We are projected again to in 1997. We may in fact set that up. This is probably fairly common to what a lot of the utilities, though, have done as a result of the disturbance.

Mr. DOOLITTLE. I want to hear Mr. Budhraja's answer, but let me say when I visited the Glen Canyon Dam, they had a maintenance schedule that went into the year 2000, projecting different things they were going to routinely do. But I assume, or maybe I should not assume, do you not adjust those according to—I mean, if there is something that comes up like this August 10th incident, you would alter that maintenance schedule, would you not?

Ms. EDWARDS. Typically, this review of the power system stabilizers would have been performed in 1997. But as a result——

Mr. DOOLITTLE. And so you updated it immediately.

Ms. EDWARDS. Yes.

Mr. DOOLITTLE. OK. Mr. Budhraja?

Mr. BUDHRAJA. Yes. There are two issues here. One is McNary and its performance and second is adequate voltage and I think the issue that happened was whether you use dynamic testing or static testing, if you assume you have voltage support when in fact you do not, you are going to run into a problem. And I think the key issue to focus on here is that all power systems must have adequate local voltage support and, as you heard earlier, it could be supplied through transmission lines, local generation, nearby generation, far away generation, cutting schedules.

Now, how each system manages that may vary, but I can tell you that on the Edison system we do look at power system stabilizers, are they operating or not and it could be that on a given plant they do not operate but that does not mean that we have inadequate voltage support because we might start other power plants that would provide the requisite amount of voltage support.

I think in terms of availability of units, our experience is not unlike PG&E's. Transmission systems tend to have the highest availability, in excess of 99 percent generally. Hydro units are next, in the 90–95 percent, and then thermal units generally are in the 80–85 percent availability range.

Mr. DOOLITTLE. If I remember the GAO report on the Corps' facilities, which I think were in the Southeastern Power Administration, I think they are getting down to where the thermal units are that you are talking about. I think it was around 84 percent for their hydro. So Southern California Edison is right up there with PG&E.

Is that the case, Marcie, that the Department of Water and Power has 90 to 95 percent?

Ms. EDWARDS. Our hydro units are still well in the nineties.

Mr. DOOLITTLE. Yes. OK. So the Corps of Engineers, at least, is significantly below your three entities, which I believe to be pretty much the industry standard.

Well, let me ask you three, if you had had adequate notice that things were going awry on August 10th up in the Portland area, would you have been able to have taken steps to avert the outage, do you think?

Mr. BUDHRAJA. I think if we had adequate notification, there is no question that some remedial actions would have been taken. The most obvious one is to reduce schedules on the intertie and increase generation in California such that you reduce your dependence on that critical artery.

Mr. DOOLITTLE. And that can happen in a matter of—what, a few minutes, a few hours? How much time does it take to do that?

Mr. BUDHRAJA. Well, I think, you know, these things can vary, but generally let me just say if there was some significant equipment outage, it may be some minutes, whether it is five to 10 minutes before the information gets shared, assuming this is not an emergency because in an emergency things would happen automatically.

We would generally then raise generation. It could be done in a matter of minutes, no more than 10 minutes, to alter schedules. Now, it can vary from a system situation. I mean, if it is not judged to be very critical, we might do it over a period of 1 hour, but the response capability exists to increase schedules within 10 minutes.

Mr. DOOLITTLE. Ms. Edwards, what do you think?

Ms. EDWARDS. It brings two thoughts to mind. One is that issue of examining what before were really non-credible events to us, multiple series of line outages, and the need now that presents itself to do that to a much larger extent. And also it highlights the dispatcher training issue.

I think particularly in the California area, we have targeted that fairly substantially over the last couple of years. There are hotlines established between the major control centers. The senior load dispatchers are empowered, they get on the phone together, they can shed customer load to stabilize the power system in probably under a minute. There is a series of very rapid actions that they can take and they are empowered to in fact do that.

We do not have, at least immediately, the environmental constraint that came about with the fish flush issue where that needs to move upwards substantially before a decision can be made. In fact, I would underscore the comment that was made, that needs

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to be pushed downward when you are talking about a power system emergency. The time to act can be very short.

Mr. DOOLITTLE. Mr. Macias?

Mr. MACIAS. In operations, because electricity travels so fast and your response time is so critical, your operators are trained to think ahead, think the worst ahead and always plan contingencies. And as you start actually seeing events occur, you start planning ahead for what else can go wrong, what could, and operators do not assess what is the probability of something occurring, they assume what if something else should occur.

As this escalating event occurred, you would have started to see escalating actions taken as the things continued. Nothing would have happened on the notification of the first line outage. Transmission lines do go out; even though, as we heard, they are the highest, most reliable systems, an outage does occur. But it is an unusual event. We consider a single transmission line to be such an unusual event, I will get woken up during the middle of the night if a single line goes out.

When the second line goes out, a third line went out, we would have started putting additional standby generation on line, gas turbines on line, to strengthen the system. We then would have started to actually cut flows.

About a month after August 10th, we had a planned maintenance outage on one of the lines on the three-line intertie and temperatures went up and the flows went up and then an outage occurred on BPA voltage support equipment on another line on their side. And communication was started and in that case the operators reduced the flows. That is the type of action that you would see. You would start seeing it associated with incremental actions.

Mr. DOOLITTLE. You are saying that even though the first line going out, while unusual, is not too great a cause for concern, but even that first line going out would wake up you in the middle of the night.

Mr. MACIAS. If it was one of PG&E's lines, yes.

Mr. DOOLITTLE. Yes. Does the fact that it is the biggest type of a line, a 500 kilovolt line, is that more significant than a 230?

Mr. MACIAS. Yes. Yes.

Mr. DOOLITTLE. So certainly by the time the second one went out, you would have the red flags clearly——

Mr. MACIAS. We would have started taking action, especially when a second line on a separate corridor, what is going on? It is so unusual of having two of those, these highly reliable lines, go out on separate corridors. You put them on separate corridors so if something happens in one you do not impact the other. Two lines going out simultaneously, at least for us, is a most unusual event.

Mr. DOOLITTLE. Now, if you had had illustrations of problems a couple, three, 4 weeks, I do not know, a few weeks ahead of the big one on August 10th, would that have triggered a comprehensive evaluation of conditions and rights-of-way and that kind of thing in your mind, in PG&E?

Mr. MACIAS. I am sorry. I missed the first part of the question.

Mr. DOOLITTLE. Well, if you had—I mean, this had happened, I believe, twice before in July where the power lines sagged into the trees and shorted out the line. Would that have triggered then a review within PG&E of its rights-of-way and things so you might have averted the——

Mr. MACIAS. Yes. We have undertaken an extensive vegetation management and tree trimming in our system over the past 2 years because we have had problems of our own with tree contact that is mostly on the distribution side.

Vikram mentioned that on his system they have not had any outages as a result of tree contact, any customer impact. We are the same.

Mr. DOOLITTLE. Let me just ask. Distribution is from—what, the substation to the end user?

Mr. MACIAS. Right. It is in the neighborhoods. It is less than 60 kv. On our system of 14,000 miles of transmission line, we experience about 15 tree contacts per year that will cause a line to correct but does not cause an outage.

Mr. DOOLITTLE. Now, say that—that will cause a line to correct?

Mr. MACIAS. A line to go out, but not cause a customer outage.

Mr. DOOLITTLE. Oh, right. OK.

Mr. MACIAS. And because of the problems we have had on our distribution side, we have had an extensive——

Mr. DOOLITTLE. Were those distribution problems, those 15, or were they transmission?

Mr. MACIAS. No, those were transmission.

Mr. DOOLITTLE. Those were transmission.

Mr. MACIAS. We have considerably more on the distribution side.

Mr. DOOLITTLE. OK.

Mr. MACIAS. Over the past 3 years, we have doubled the amount of money and effort we have spent into tree trimming. We also cut back on any herbicide or chemical vegetation management, but the loss of that as one tree trimming action does not mean you cannot do others.

We found that by being very smart with tree trimming and using tree experts on how you trim trees you can actually train it to grow away from your transmission lines.

Also on transmission, the majority of our outages occur from trees that are outside our right-of-way. The worst we have is on the California north coast. We have 80-foot high redwoods and our right-of-way is only 40 feet tall and the lines are in the middle.

Mr. DOOLITTLE. You mean the right-of-way has a vertical dimension? Is that what I understood you to say?

Mr. MACIAS. Well, your line, you heard before that it will sag.

Mr. DOOLITTLE. Yes.

Mr. MACIAS. Your high voltage ones, especially the long spans, will sag as much as 40 feet. They will also sway in the wind. So essentially you have a circle and a corridor that you have to keep protected.

Now, you asked earlier about some of the problems with the regulations. Our pet peeve, my pet peeve is the regulations call for a minimum distance from the wire, so essentially you have to have a circle around your wire sitting there stagnant. The trees will blow in the wind so in some cases, it is 20 feet, you have to have it 20 feet. It says minimum. There is nothing about maximum. And we have gone in and tried to trim greater and we have gotten communities and other agencies after us that we are too aggressively trimming trees.

Well, you go in there and you trim your minimum and you cannot do a maximum, the next day the wind blows the tree in or it grows, you are now in violation.

Mr. DOOLITTLE. Well, so can these lines go out—surely it is not 40 feet from side to side, is it?

Mr. MACIAS. Some of them can swing as much as 20 feet out. There is a big arc that these things can swing in winds. They are designed to withstand up to 100 mile per hour winds, cross-winds that we can have in storms in California.

Mr. DOOLITTLE. But you said your right-of-way has a certain limit. Which right-of-way?

Mr. MACIAS. Just about all right-of-ways—a 500 kv right-of-way has a right-of-way, I believe, of about 200 feet and then a 230 is like maybe 100 feet and then a 110, so it shrinks by the voltage.

Mr. DOOLITTLE. And this is how wide the right-of-way is, you are talking about?

Mr. MACIAS. Correct. And our preference for right-of-ways, it varies by property owners. It is what the original easement was negotiated with the property owners. Where we have the rights, we prefer to just clear cut it out, remove the trees. Not only does that reduce your tree trimming costs because you do not have to go in there every year and trim it, but when you do have an outage, your access and your response time is greatly reduced.

Mr. DOOLITTLE. Now, did PG&E discontinue entirely your herbicides?

Mr. MACIAS. I wish I had looked into that. I do not know for sure, but I believe—if we have not eliminated it, we have dramatically reduced it.

Mr. DOOLITTLE. So then you are forced to labor——

Mr. MACIAS. Forced to use other methods. Yes.

Mr. DOOLITTLE. Well, find out, unless you know the year, find out. I would be interested in knowing what year that happened because it sounds like BPA is going to reinstitute herbicides because they have a different—well, I guess their whole area would be like the north coast of California in terms of how fast trees grow.

Mr. MACIAS. Our herbicide is a chain saw.

Mr. DOOLITTLE. Right.

Ms. Edwards, what is your situation?

Ms. EDWARDS. As far as herbicides, I would probably have to answer for the record. I would have to do some research.

Mr. DOOLITTLE. OK. That is fine.

Ms. EDWARDS. But bear in mind, too, in Southern California, very frequently the largest thing near some of these transmission towers is a tumbleweed crossing the desert.

Mr. DOOLITTLE. Right. You do not have the same problem.

Mr. Budhraja?

Mr. BUDHRAJA. I would have to get back to you on the herbicide issue.

[The response may be found at end of hearing.]

Mr. DOOLITTLE. OK. Well, let me just ask the three of you, getting back to the other issue of appropriate notice—we did not get the answers on appropriate notice, did we? If you had had appropriate notice from BPA about the problem with their lines going down, could you——

Ms. EDWARDS. I would have to echo Mr. Macias. It would be the cascading or cumulative nature of the event that would have caught our attention. A single 500 kv relay would really be considered as routine trouble on a power system and would not necessarily draw a large amount of notice.

Mr. DOOLITTLE. So you do not get up in the night——

Ms. EDWARDS. They wake me up at two.

Mr. DOOLITTLE. For two?

Ms. EDWARDS. Right.

Mr. DOOLITTLE. All right.

Ms. EDWARDS. And actually there are some, as we talked about the discussion earlier regarding key facilities, there are some facilities and some circuits that are so important to all of us on the system that that type of notification will take place. But on the whole, I would not normally hear about it until it started to cascade. And we would have taken the same type of actions. We would have committed additional spinning generation with some potential that there may have been some greater loss of either transmission paths or voltage support, so we would have taken a proactive stance as well.

Mr. DOOLITTLE. If you had had it happen twice before, and I realize one of those times was not the BPA, I think it was in Idaho, it was the Idaho Power Company, I guess, but it was a widely reported event, if you had had that set of circumstances, would that have caused you to examine your own areas to make sure that you were not going to experience a problem like that?

Ms. EDWARDS. A lot of the work that we undertook, the voltage support examination, the tree trimming programs, we actually initiated as a result of the July 2nd instance.

Mr. DOOLITTLE. Oh, as a result—oh, all right. So you took those things very seriously.

And, Mr. Budhraja, tell us——

Mr. BUDHRAJA. Yes. I think an event like July 2nd is a very serious event and we reviewed our procedures after that. We lost 260,000 customers on that day. It was not as severe, obviously, as the August 10th, but any time you have customer interruption, it is a very significant issue. We pay a lot of attention to it and we just do not like to have those things happen. Period.

Mr. DOOLITTLE. So if you had had appropriate notice from BPA, would you have been able to take action to protect yourselves?

Mr. BUDHRAJA. Yes. I think—I just would echo what you already heard from Ms. Edwards and Mr. Macias and that is if it was understood the state of the system had weakened because of multiple 500 kv lines out, there is no question in my mind that we would have taken protective action.

Now, I think one line, if it is not viewed as critical, that is a judgment we do leave to the system dispatchers, but you just cannot have a very weak system which can—and operating in a way in a power system in which the next contingency can take the whole system down. You just do not do that. I think Mr. Jennings mentioned earlier N–1, N–2 and that is what we do look at, you know, that the power system should be able to withstand the outage of the next contingency without affecting customer loads.

Mr. DOOLITTLE. And when do they wake you up at night? Does that happen?

Mr. BUDHRAJA. They wake a lot of people up at night. I guess, if it is really serious, I will get woken up, too.

Mr. DOOLITTLE. One 500 kilovolt line would not necessarily trigger that.

Mr. BUDHRAJA. No, it would not.

Mr. DOOLITTLE. Would two trigger it?

Mr. BUDHRAJA. We have a slightly different reporting structure, so I get spared even on two.

Mr. DOOLITTLE. All right. But, I mean, somebody——

Mr. BUDHRAJA. Yes.

Mr. DOOLITTLE. Some person in charge is——

Mr. BUDHRAJA. Yes. Yes. I would like to, if I may, with your permission, Mr. Chairman, address another issue that came up in the earlier discussion, the issue on July 3rd and Idaho cutting off power to Boise?

Mr. DOOLITTLE. Yes.

Mr. BUDHRAJA. One of the rules in an interconnected system is if you have a problem on your system, you should correct it and not allow it to propagate to other systems, so we commend Idaho for doing it on July 3rd. I wish they had done it on July 2nd also and not allowed it to propagate beyond the Northwest.

Mr. DOOLITTLE. And they could have done it on July 2nd, I suppose.

Mr. BUDHRAJA. Well, I think if you have a low voltage situation, we have an obligation to either increase local generation or reduce load such that we do not impact other systems.

Mr. DOOLITTLE. Now, what is the possibility that your utilities would have continued to take Northwest power even with this notice that things were going awry simply because it was cheaper power? Would any of them have continued to have done that at that point?

Mr. MACIAS. On August 11th, you heard earlier where we were declaring it an emergency. We were seeing all-time record highs, 5 percent even higher than we had previously seen the year before. We had lost 2200 megawatts of our nuclear capability. We were on the ragged edge. We had already derated the line, BPA and PG&E. We would not have increased it. If they could not have taken the emergency action to get The Dalles plant operating, we would have suffered the consequences with our customers.

As Vikram said, you have a responsibility to operate according to WSCC criteria and procedures in your service territory. So we would not have increased the flows even for customer service. Even when we got beyond that hurdle, we were suffering costs of $100,000 a day and lost increased economic supplies. But just like you do with any commodity, you have a very pivotal supply to you, if your supplier, if you have a lack of confidence in that supply, you do not rely on it, even if it is economical.

Mr. DOOLITTLE. Your company and that of Mr. Budhraja are subject to the public utilities commission, right?

Mr. BUDHRAJA. Yes.

Mr. MACIAS. Correct.

Mr. DOOLITTLE. So I know those to be both very fine companies, but in addition to just being good corporate citizens, I mean, you would have suffered significantly from penalties levied against you, would you not?

Mr. MACIAS. Our president, Mr. Conlon, was very diplomatic in his answer, but when you asked the question I could not help but be squirming in my seat. With the clear WSCC standards, they would use those as the standards of criteria we were not following.

As he mentioned, we just yesterday received the maximum fine allowable because we did not meet this 20-second call center response that is the most stringent of any utility in the United States.

Mr. DOOLITTLE. By the way, how many seconds was it, anyway? Apparently, you went over the 20 seconds, that is the standard, so how many seconds was it taking?

Mr. MACIAS. Some of them, because we were receiving as many as 4 million calls——

Mr. DOOLITTLE. Oh, as a result of this August 10th outage?

Mr. MACIAS. This was another storm. This was unrelated.

Mr. DOOLITTLE. Oh, OK.

Mr. MACIAS. This was another major storm with a lot of storm-related outages. The commission felt, as I understand it, we did not meet our goals and standards that they had requested of us and we had committed to in our 20-second call response.

Mr. DOOLITTLE. How long did it take, 30 seconds?

Mr. MACIAS. Well, some of them could not get through.

Mr. DOOLITTLE. Just could not get through? So what are you supposed to do, hire more operators?

Mr. MACIAS. You put in more lines.

Mr. DOOLITTLE. More lines?

Mr. MACIAS. And you hire more operators and you have back-up systems because you do not sit there and man for 24 hours a day for that.

Mr. CONLON. They have met it on every one since then.

Mr. DOOLITTLE. OK. What about the issue of taking the cheaper power, assuming the risk because it is cheaper. You would not have done that, would you?

Ms. EDWARDS. The economics become very secondary in an electrical emergency situation. Even though the Department of Water and Power is not a CPUC regulated entity, our relationship with the Western systems has been very staunch for a number of years. I am held personally accountable that we operate within the Western systems criteria for interconnected system operation and that will and does, unfortunately, very often, take precedence over the economic criteria because the reliability is the first thing we need to maintain.

Mr. DOOLITTLE. One of the things we seemed to hear from almost everyone today was that if you are generating power you ought to have to belong to the WSCC.

Ms. EDWARDS. Not only just generating, sir. I would suggest that it is a broader participation than that. Part of the difficulty in transitioning to this competitive environment is that utilities find themselves bearing more of the economic brunt for the reliability issues. And so the mechanisms to establish more of a parity such that that is spread amongst everyone deriving benefit from using the system is a very critical issue for us.

Mr. DOOLITTLE. So, do you all support the idea that you ought to have to join and be subject to mandatory sanctions for failure to comply with the standards?

Ms. EDWARDS. I would say from a Los Angeles position, we are already in compliance with Western systems, so the economic impact to us would be nil and the advantages by having others brought in and forced to comply would be nothing but to our benefit.

Mr. DOOLITTLE. In other words, the supply of power is not just like delivering some commodity because it is an essential service and so the issue of reliability is critical and therefore it is not strictly speaking just a free market situation. There is more responsibility that goes with providing the—what do we call it, it is a service, is it not? Anyway, getting people who come into it who presently are not subject to obeying the standards or at least they do not have to belong, I guess they can withdraw at any time they choose.

Mr. BUDHRAJA. I think the issue is reliability first, economics second. I mean, obviously we do not want to spend money where we do not have to, but it cannot be to compromise reliability. An analogy I would use is the air traffic system. Obviously if a plane is in a hold pattern, they are burning up fuel, it is costing them money, but the air traffic controllers have absolutely reliability first, safety first, and economics second. That is the way we operate our power system and that is the way it should be in the future.

To the point of mandatory protocols, I would just suggest that at least in my judgment, the issue of membership may be more exaggerated than what we need to do and that is there are going to be hundreds of players in the marketplace. We do not need necessarily all of them to be members of the reliability council, but they must play by the rules, they must have the obligation to comply, just as everybody who flies has to comply with the rules in terms of the air safety situation.

But that is not to say that it should not be mandatory protocols. I think we need mandatory protocols, we need a mandatory obligation to comply, not just on the generators, but also the transmission companies and marketeers.

Mr. DOOLITTLE. Ladies and gentlemen, thank you very much for your testimony. We may have further questions of you and the other panelists. We would ask you to respond quickly when we send them to you.

I have found this hearing to be very informative. I really appreciate your participation and that of the previous panelists.

Again, we thank the City of Los Angeles and this Department of Water and Power for the many courtesies it has extended this Subcommittee.

The record will be held open for a few days for comments—two weeks, to be specific.

With that, the Subcommittee will stand adjourned.

[Whereupon, at 1:57 p.m., the Subcommittee was adjourned; and the following was submitted for the record:]

PREPARED STATEMENT OF MARK B. BONSALL

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Statement of the Western Systems Coordinating Council Regarding Issues and Recommendations Concerning the August 10, 1996 Western Power Outage

Before the Water and Power Resources Subcommittee of the
Committee on Resources
U.S. House of Representatives
November 7, 1996

By Mr. Mark B. Bonsall
Chairman, Western Systems Coordinating Council
and
Associate General Manager Marketing, Customer Service, Financial and Planning
Salt River Project
Phoenix, Arizona

Chairman Doolittle and members of the Water and Power Subcommittee, it is a distinct pleasure to appear before you today to discuss the August 10, 1996, power outage that affected the western United States, western Canada, and northern Mexico, the actions taken following the outage, and the conclusions and the recommendations that have been developed as a result of the outage.

I am Mark Bonsall, chairman of the Western Systems Coordinating Council and associate general manager, marketing, customer service, financial and planning at Salt River Project in Phoenix, Arizona.

WSCC is the largest and most diverse of the 10 regional reliability councils of the North American Electric Reliability Council (NERC). WSCC's service territory extends from Canada to Mexico, an area of nearly 1.8 million square miles. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 western states in between. Due to the vastness and diverse characteristics of the region, WSCC's members face unique challenges in coordinating the day-to-day operation and long-range planning required to provide reliable and affordable electric service to the more than 59 million people within the WSCC region.

The interconnected transmission system within the WSCC region is known as the Western Interconnection. It is one of the five major electric system networks in NERC.

OVERVIEW OF THE AUGUST 10 POWER OUTAGE

At 3:48 p.m. pacific advanced standard time (PAST) on Saturday, August 10, a major power outage occurred on the Western Interconnection, interrupting service to 7.5 million customers for periods ranging from several minutes to about nine hours.

In the hours before the power outage, three lightly loaded 500,000-volt lines (Big Eddy-Ostrander, John Day-Marion, and Marion-Lane) in the Portland area were forced out of service. These 500,000-volt lines were providing voltage support for the transmission system. Two of the line outages were caused by flashovers (short circuits) to trees. The third line was forced out of service because a circuit breaker was out of service when the second line outage occurred. While none of these line outages were individually judged to be crucial by Bonneville Power Administration dispatchers, the cumulative impact resulted in a weaker system. Voltages were adjusted but no schedules were reduced. In addition, two 115,000-volt transmission lines, two 500,000-volt circuit breakers, and a 500,000/230,000-volt transformer, all in the Portland area, were out of service for modifications and/or repairs. These outages contributed to the system stress following the subsequent loss of the Keeler-Allston 500,000-volt line.

The power outage effectively began when the heavily loaded Keeler-Allston 500,000-volt line, which is in the Portland, Oregon, area, sagged too close to a tree and flashed over. Loss of the Keeler-Allston 500,000-volt line precipitated the overloading and tripping of two underlying parallel transmission lines in the Portland area, one due to a flashover to a tree and one due to a relay malfunction, which depressed the surrounding transmission system voltages. The depressed voltages led to the subsequent tripping of hydroelectric generating units at the McNary Dam due to excitation equipment problems. This combination of events triggered increasing voltage oscillations on the interconnected transmission system, eventually causing protective devices to trip the three 500,000-volt California-Oregon Intertie (COI) lines (three of the four major transmission lines that tie the Pacific Northwest to California). The outage of the these three lines resulted in transmission and generation outages that culminated in the system separating into four islands. (See Attachment I.)

System islanding is used in the West as a safety net to prevent a total blackout, minimize the number of customers affected, and minimize the time required to restore customer service. Because islanding did not occur in a controlled manner, loss of the COI resulted in the loss of approximately 21,400 megawatts of generation and approximately 27,400 megawatts of underfrequency load shedding (over 7 million customers) in northern California and the Southwest (see table below).

AUGUST 10, 1996, POWER OUTAGE				
	Customers Affected	Load Shed (MW)	Generation Tripped (MW)	Restoration Time (hours)
Alberta	191,904	968	146	1
Northwest	209,858	2,099	5,689	4
Southwest	4,226,972	15,982	13,497	6
Northern California	2,861,343	11,440	7,918	9
Totals	7,490,077	30,489	27,250	9

<u>CONTRIBUTING FACTORS</u>

The interconnected transmission system from Canada south through Washington and Oregon to California was heavily loaded because of high temperatures (near or above 100 degrees) throughout much of the WSCC region. In addition, because of the excellent hydroelectric conditions in Canada and the Northwest, the amount of power being transferred (including large economy transfers) from Canada into the Northwest and from the Northwest to California was high, but within established transfer capability limits.

IMMEDIATE ACTIONS TAKEN

In the wake of this outage, an emergency meeting of senior management from the western utilities, the U.S. Department of Energy, and the state regulatory community was convened on August 12. A lower power flow transfer limit (from 4,800 megawatts to 3,200 megawatts) was established for the California-Oregon Intertie until additional studies have been conducted and the results approved by a newly established WSCC Operating Capability Policy Committee. In addition, Bonneville Power Administration (BPA) began a comprehensive study to assess the voltage support capability of its system. BPA also agreed to report all outages of 500,000-volt transmission lines and other key facilities on its system. In conjunction with the U.S. Army Corps of Engineers, BPA also initiated a review to understand the loss of the McNary generators and to prevent their loss in the event of a future disturbance. Changes have been made to the McNary excitation systems. As an additional precaution, the Northeast/Southeast Separation Scheme was placed back in service. Additionally, all WSCC members have been asked to review their tree trimming programs, their system's voltage support capability, and the NERC recommendations set forth in the publication entitled "Survey of the Voltage Collapse Phenomenon."

COMPREHENSIVE OUTAGE ASSESSMENT

As is standard practice for WSCC and its members following a system-wide power outage, a task force of industry experts conducted a thorough review of the power outage and recommended actions to lessen the potential for the occurrence of a similar event in the future. As part of the standard outage analysis and review process, WSCC procedures, policies, and monitoring activities are being reviewed to identify any necessary improvements.

The final report on the August 10 outage includes 32 conclusions and over 90 associated recommendations. All recommendations are logged and tracked until they are completed. The report has been submitted to the U.S. Department of Energy and the North American Electric Reliability Council.

Key Findings

In reviewing the August 10 outage, the task force identified four key findings:

- the interconnected transmission system was unknowingly being operated in violation of WSCC Reliability Criteria;

- transmission line right-of-way maintenance, operating studies, and system operating instructions to dispatchers were inadequate;

- contingency plans should have been adopted to mitigate the effects of an outage of the Keeler-Allston 500,000-volt transmission line, and

- the loss of the 13 McNary hydroelectric generating units in the Northwest was a major factor leading to the outage of the three 500,000-volt California-Oregon Intertie lines and the subsequent islanding of the WSCC interconnected system.

Corrective Actions

This power outage indicates the need to identify and implement strategies that will minimize the potential for the more severe, unforeseen events, and should such events occur, minimize the impact of the outages. It also highlights the need for continued vigilance to reasonably ensure that all equipment will operate as expected.

WSCC and the other regional councils are in the process of implementing additional security process measures. These measures will enhance interconnected system reliability through the exchange of information required to augment system security and reliability, including on-line power flow and security analysis and increased system monitoring. These measures will enhance the operators' ability to identify potential problem outages and take corrective actions. Within the WSCC region, there will be four security coordinators responsible for the active monitoring of electric system conditions on a real-time basis to proactively anticipate and mitigate potential problems and coordinate restoration following a system emergency.

In addition, to safeguard the reliability of interconnected electric system operation, numerous technical studies are conducted each year to reasonably ensure that critical operating conditions are thoroughly examined and evaluated. These studies include assessments of low probability events that are expected to result in system islanding and underfrequency load shedding. Islanding and underfrequency load shedding are protective actions used in the West for severe low probability disturbances to stabilize the system, minimize customer interruptions, and allow rapid system restoration. Additional studies are being conducted to ensure a broad range of operating conditions have been adequately studied and that the system is being operated in compliance with WSCC and NERC criteria and policies. The WSCC members are looking at a wide variety of conditions and contingencies to ensure that the system is planned and operated within the established WSCC Reliability Criteria.

SUMMARY

In all likelihood, the August 10 power outage could have been avoided if contingency plans had been adopted to minimize the effects of an outage of the Keeler-Allston 500,000-volt line in the Pacific Northwest. In addition, the task force determined that the loss of the McNary generating units and inadequate tree-trimming practices, operating studies, and instructions to dispatchers played a significant role in the severity of this disturbance.

Actions Required to Ensure Reliability

As the electric industry becomes more competitive, we must make certain that interconnected system reliability is preserved. We must ensure that all entities that own, operate, or use the interconnected transmission system are complying with the established criteria, guidelines, policies, and procedures of WSCC and NERC. I believe there are three essential steps that must be taken to ensure system reliability and a level playing field in an era of competition:

1) mandatory compliance with established standards;
2) mandatory membership in the regional reliability councils and NERC; and
3) expanded compliance monitoring, with appropriate incentives, sanctions, or fines.

As the industry is restructured and competition increases, it will become even more important for **ALL** market participants to adhere to the "rules of the road," especially since fewer participants (if any) will be willing to go the extra mile, and incur the added expense, to meet a competitor's obligation for ensuring reliability. It is for this reason, that the industry widely shares the view that voluntary compliance will no longer be adequate.

To ensure mandatory compliance, we must be able to monitor those involved and correct those in noncompliance. This raises some questions. How do you ensure compliance? Is peer pressure enough? How will we ensure an organization implements corrective actions? Will fines or sanctions become necessary?

First, we need to consider economic-based mechanisms to ensure compliance and accountability — enforceable mechanisms, such as financial incentives in the form of market trade privileges or possibly compliance-based operator's licenses that would somehow allow participants to reduce their costs. Where financial or business incentives cannot be developed to ensure compliance and accountability, the regional reliability councils must have the ability to impose sanctions or fines on noncomplying members, so that one participant's noncompliance does not degrade reliability or increase costs for other market participants. Consequences for noncompliance must be applied in a timely, consistent, and nondiscriminatory manner.

The next question is ... How do you ensure compliance with the established "rules of the road" without mandatory membership in the regional councils and NERC, especially with all of the new players entering the industry? If membership is not mandatory, what stops an organization from withdrawing its membership if it does not agree with the noncompliance findings, fines, sanctions, etc.?

By mandating membership, all essential players will be at the table. Everyone will have a hand in developing the compliance standards, allaying the fear of discrimination and ensuring an understanding of the adopted standards. Everyone will be required to comply with established standards and will not be able to terminate their membership to merely avoid mandatory compliance. Everyone will participate in the necessary functions of data collection, reliability assessments, and regional operation and planning. Everyone will have a stake in and be contributing financial support to promoting regional reliability. Mandatory membership will impart a sense of equity among all entities, and will promote cooperation and coordination ... something we may see less of as competition increases.

We must remember, however, that the regional councils and NERC have the ability to mandate compliance, but not to mandate membership. Mandating membership will require state and/or federal legislation or other action.

As in a quality assurance program, there needs to be a monitoring program with checks and balances. Consequently, compliance monitoring will be an essential element for preserving reliability. Reliability must be maintained moment by moment; therefore, compliance with reliability standards must be monitored on a continuous basis. We believe that NERC and the regional reliability councils will need to expand their compliance monitoring programs if we are to ensure reliability and a level playing field.

No matter how dramatically the industry changes and evolves, mandatory compliance, reliability monitoring, enforcement capability, and accountability will be essential for ensuring reliability.

For over 30 years, NERC and the regional councils have been the caretakers of reliability through the cooperative development of NERC and regional council policies, procedures, and criteria ... and voluntary compliance with these standards. As the industry is restructured and competition increases, it will become even more important that the electric industry has a structure in place with the necessary authority and tools to ensure **ALL** market participants adhere to these "rules of the road." WSCC's Agreement states that its members are responsible for meeting the established criteria, policies, and procedures. I anticipate that in January of 1997 the NERC Board of Trustees will adopt a resolution making compliance with its policies mandatory. NERC also will continue its oversight role in monitoring the security processes being implemented by the 10 regional councils to ensure they are consistent with NERC's recommendations.

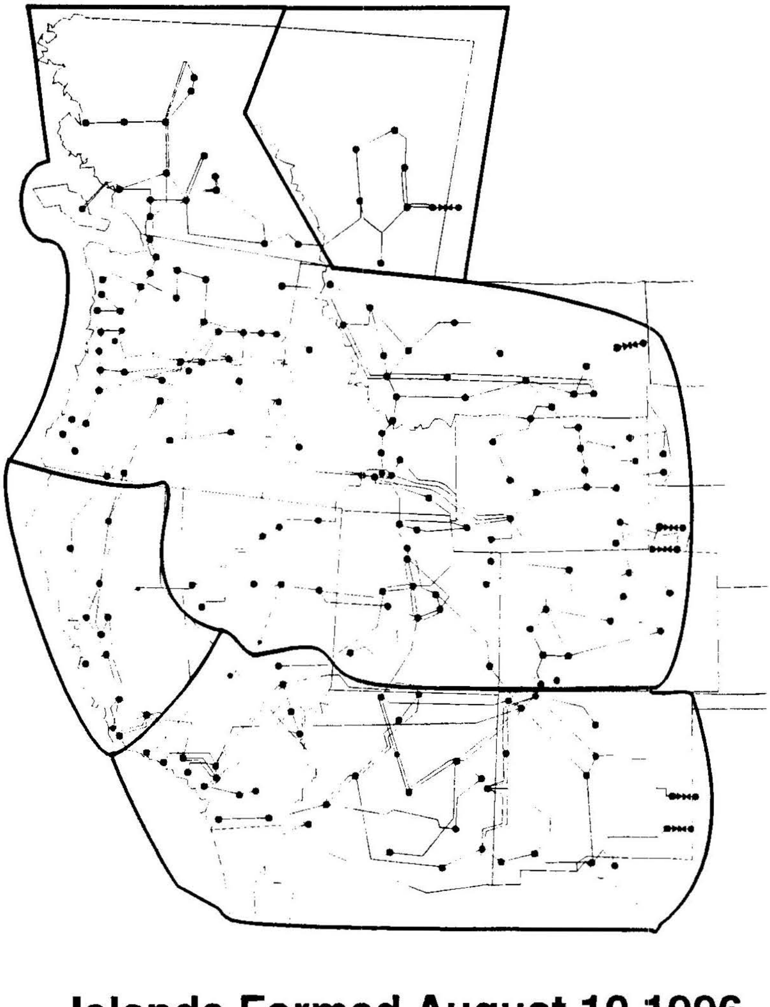
There is no reason to doubt the ability, appropriateness, and the resolve of NERC and the regional councils to continue to establish and monitor compliance with the required reliability standards. As the Department of Energy stated in its report to the President, the "... self-regulated system for ensuring electric system reliability through NERC and the regional reliability councils has worked quite well, and works well today. It can continue to work well in the future ..." and "WSCC and NERC have committed to take actions to enhance accountability for reliability, improve the tracking of compliance with reliability standards, and address the pace of industry change."

Given the quick and decisive steps being taken by the industry toward mandatory compliance and the implementation of security processes to ensure reliability, I see no need for federal legislation that would require the government to develop reliability criteria or to implement mechanisms for enforcing compliance with the "rules of the road." However, as previously noted, federal or state action mandating membership in the reliability councils and NERC is needed to equitably administer and ensure compliance with the "rules of the road" that have been etablished to preserve reliability.

Mr. Chairman and members of the Water and Power Subcommittee, this concludes my statement. I would be pleased to address any questions you may have.

Attachment I

Islands Formed During the August 10 Power Outage



Islands Formed August 10,1996

Western Systems Coordinating Council

WESTERN SYSTEMS COORDINATING COUNCIL

DISTURBANCE REPORT

For the Power System Outage that Occurred on the Western Interconnection

August 10, 1996 *1548 PAST*

Approved by the WSCC Operations Committee on October 18, 1996

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TABLE OF CONTENTS

System Identifiers

Throughout the report, organizations are identified using the acronyms listed below.

APS - Arizona Public Service Company
BPA - Bonneville Power Administration
BURB - Burbank, City of
BCHA - British Columbia Hydro and Power Authority
CDWR - Department of Water Resources/California
CSU - Colorado Springs Utilities
CFE - Comision Federal de Electricidad
EPE - El Paso Electric Company
EWEB - Eugene Water & Electric Board
FARM - Farmington, City of
GLEN - Glendale, City of
IPC - Idaho Power Company
LDWP - Los Angeles Department of Water and Power
MWD - Metropolitan Water District/ Southern California
MID - Modesto Irrigation District
MPC - Montana Power Company, The
NEVP - Nevada Power Company
NCPA - Northern California Power Agency
NWPP - Northwest Power Pool
OXGC - Oxbow Geothermal Corporation
PG&E - Pacific Gas and Electric Company
PAC - PacifiCorp
PASA - Pasadena, City of
PEGT - Plains Electric Generation and Transmission Cooperative, Inc.
PGE - Portland General Electric Company
PNM - Public Service Company of New Mexico
COPD - PUD No. 1 of Cowlitz County
DOPD - PUD No. 1 of Douglas County
GCPD - PUD No. 2 of Grant County
SNPD - PUD No. 1 of Snohomish County
PSPL - Puget Sound Power & Light Company
SMUD - Sacramento Municipal Utility District
SRP - Salt River Project
SDGE - San Diego Gas & Electric Company
SCL - Seattle Department of Lighting (Seattle City Light)
SPP - Sierra Pacific Power Company
SCE - Southern California Edison Company
TCL - Tacoma Department of Public Utilities (Tacoma City Light)
TNP - Texas-New Mexico Power Company
TAUC - TransAlta Utilities Corporation
TSGT - Tri-State Generation & Transmission Association, Inc.
TEP - Tucson Electric Power Company
TID - Turlock Irrigation District
USBR - U.S. Department of Interior Bureau of Reclamation
 USDO - (Denver Office)
 USGP - (Great Plains)
 USLC - (Lower Colorado)
 USMP - (Mid-Pacific)
 USPN - (Pacific Northwest)
 USUC - (Upper Colorado)
VERN - Vernon, City of
WWPC - Washington Water Power Company
WAPA - Western Area Power Administration
 WAHQ - (Golden, Colorado)
 WALC - (Phoenix, Arizona)
 WALM - (Loveland, Colorado)
 WAMP - (Sacramento, California)
 WAUC - (Salt Lake City, Utah)
 WAUM - (Billings, Montana)

I. SUMMARY AND INTRODUCTION

At 1548 PAST on Saturday, August 10, a major system disturbance separated the Western Systems Coordinating Council (WSCC) system into four islands, interrupting service to 7.5 million customers for periods ranging from several minutes to about nine hours. This disturbance effectively began with the loss of the Keeler-Allston 500-kV line in the Portland area, due to inadequate right-of-way maintenance, which overloaded parallel lines and depressed transmission voltages. These conditions led to subsequent tripping of additional lines and McNary generating units, triggering increasing oscillations that eventually caused protective devices to trip the three 500-kV California-Oregon Intertie (COI) lines and other major lines.

In addition to interrupting service to a large number of customers, this severe disturbance tripped fifteen large thermal and nuclear units in California and the Southwest, delaying load restoration. A few large units did not return to service for several days, requiring operators to purchase emergency power to serve the high, hot-weather loads experienced during the following days.

In the wake of this disturbance, a lower limit (3,200 MW) was maintained on the COI to account for operational limits on generation at McNary (exciter problems) and The Dalles (fish protection). To avoid implementing an emergency operating plan in California which, under a worst case scenario, could have necessitated rotating blackouts, the COI limit was increased to 3,600 MW from August 12 to August 14. This was made possible, on an emergency basis, by temporarily reducing Endangered Species Act (ESA) compliance spills and increasing generation output at The Dalles.

Several factors contributed to the occurrence and severity of this disturbance.

1. HIGH NORTHWEST TRANSMISSION LOADING

   The 500-kV and underlying interstate transmission system from Canada south through Washington and Oregon to California was heavily loaded due to:

   - Relatively high loads, caused by hot weather throughout much of the WSCC region.

   - Excellent hydroelectric conditions in Canada and the Northwest, leading to high power transfers (including large economy transfers) from Canada into the Northwest and from the Northwest to California. System conditions in the Northwest were similar to the conditions prior to the July 2, 1996, disturbance, except power was flowing into the Northwest from Idaho. This allowed exports to California on the COI of up to 4,750 MW, as determined by operating nomogram limits developed by BPA, PG&E, IPC, and PAC following the July 2 disturbance.

   - During these periods of high transmission loading, BPA operators had previously noticed small changes in power flows causing large changes in voltage, indicating voltage support problems in the Northwest during stressed operating conditions.

2. EQUIPMENT OUT OF SERVICE

- In the hours before the disturbance, three lightly loaded 500-kV lines (Big Eddy-Ostrander, John Day-Marion, and Marion-Lane) in the Portland area were forced out of service. These 500-kV lines were providing reactive power support for the transmission system. Two of the outages were caused by flashovers to trees resulting from inadequate right-of-way maintenance, and one outage resulted from a circuit breaker being out of service.

- The Allston-Rainier 115-kV line was out of service due to degraded capability of line hardware. The Longview-Lexington 115-kV line was out of service for fiber-optic cable installation. These outages contributed to the system stress following the loss of the Keeler-Allston 500-kV line.

- A 500-kV circuit breaker at Marion, a 500-kV circuit breaker at Keeler, and the 500/230-kV transformer at Keeler were out of service for modification. The Static VAR Compensator (SVC) at Keeler was reduced in its ability to support the 500-kV system voltage due to the transformer outage (the SVC is tied to the 230-kV side). Since Northwest loads are historically lower in the summer than in the winter, BPA performs most system maintenance during the summer.

3. TRIGGERING EVENTS

- At 1542:37 PAST, the heavily loaded Keeler-Allston 500-kV line sagged too close to a tree and flashed over, additionally forcing the Pearl-Keeler 500-kV line out of service due to the 500/230-kV transformer outage and breaker replacement work at Keeler. These outages overloaded the parallel 230-kV and 115-kV lines into the Portland area and depressed the 500-kV voltage at Hanford from 527 to 506 kV. The reactive power output from McNary increased to its maximum sustainable level to support the voltage, and held this level for nearly five minutes.

- Approximately five minutes later, (about 1547:29 PAST), the St. Johns-Merwin 115-kV line tripped due to a zone 1 KD relay malfunction, contributing to the loading of other lines parallel to the Keeler-Allston 500-kV line. (The exact time of this event is not known.)

- At 1547:36, the overloaded Ross-Lexington 230-kV line sagged too close to a tree and flashed over, resulting in loss of 207 MW of Swift generation, thus further depressing system voltage and further increasing the demand for reactive power output from McNary generating units, already at their maximum sustainable level. This outage also contributed to loading on the lines parallel to the Keeler-Allston 500-kV line.

- At 1547:37, units at McNary began tripping (due to excitation equipment problems), and increasing power and voltage oscillations began. These oscillations increased in magnitude for approximately 70 seconds, until the three 500-kV COI lines relayed due to low voltage (less than 315 kV on the Malin 500-kV bus) at 1548:52. These oscillations were a major factor leading to the separation of COI and subsequent islanding of the WSCC system.

- Some of the power that had been flowing to northern California on the COI surged east then south through Idaho, Utah, Colorado, Arizona, New Mexico, Nevada and southern California. Numerous transmission lines in this path subsequently tripped due to out-of-step conditions and low voltage. Although several lines between Arizona and southern California tripped, the two areas remained tied together through remaining lines.

4. KEY FACTORS

- BPA's right-of-way maintenance was inadequate. Consequently, BPA's failure to trim trees and remove identified danger trees caused flashovers on and the loss of several 500-kV transmission lines, the last of which led to overloads and cascading outages throughout the Western Interconnection.

- BPA operators were operating the system in a condition in which a single contingency outage (the Keeler-Allston 500-kV line) would overload parallel transmission lines. They were aware that on July 13, the Pearl-Keeler 500-kV line sagged too close to a tree, flashed over and tripped. This forced open the Keeler-Allston 500-kV line at Keeler due to a breaker outage. The outages loaded the parallel Longview-Allston No. 4 115-kV line to 109 percent. Additionally, a jumper on the parallel Allston-St. Helens 115-kV line burned open within two minutes due to failure of conductor hardware that had degraded. It was not loaded above its thermal rating. The two Allston-Trojan 230-kV lines and the Ross-Lexington 230-kV line loaded to their thermal limits. Loading on other lines also increased substantially. While this incident did not lead to cascading outages, it should have served as a warning prior to the August 10 outage and led to further technical analysis.

  BPA operators were unknowingly operating the system in a condition in which the Keeler-Allston 500-kV line outage would trigger subsequent cascading outages because adequate operating studies had not been conducted. Operating in a condition where cascading outages could occur is a violation of the WSCC Minimum Operating Reliability Criteria.

- In the hour and a half prior to the disturbance, BPA's Big Eddy-Ostrander, John Day-Marion and Marion-Lane 500-kV lines were forced out of service. While none of these lines were individually judged to be crucial by BPA dispatchers, the cumulative impact resulted in a weaker system. BPA did not widely communicate these outages to other WSCC members nor did they reduce loadings on lines or adjust local generation as precautionary measures to protect against the weakened state of the system.

BPA notified PGE of maintenance outages in effect, but did not notify other WSCC members. BPA did not widely communicate the forced line outages to other WSCC members, precluding them from making system adjustments had they perceived a need to take such action. BPA did not consider these to be key facility outages for reporting purposes.

- All the units at McNary tripped due to exciter protection as units responded to reduced voltage after the Keeler-Allston 500-kV and subsequent line trips. Even though the loss of McNary units (of ten units operating, three tripped immediately prior to COI separation and two tripped after separation) during the July 2 disturbance had demonstrated problems with the excitation systems on these units, this information had not yet been analyzed and factored into studies performed to develop COI/Midpoint-Summer Lake and other operating limits after July 2. Additionally, some other area generators did not respond to support voltage to the extent modeled in studies used by WSCC utilities.

- The Dalles had only five of 22 generating units operating, generating a total of 320 MW, due to spill requirements imposed to protect salmon smolts migrating downstream, significantly diminishing the voltage support available for the transmission system. The effect of this known operating constraint had not been factored into system studies.

- Growing system oscillations resulted in increasing voltage and power swings on the COI, leading to COI instability and separations. The growing oscillations may be attributed to an increased electrical angle between northwest generation and the COI due to:

  - weakening of the transmission system (loss of Keeler-Allston 500-kV, Ross-Lexington 230-kV and other, lower voltage lines)

  - a shift of generation to Grand Coulee and Chief Joseph following tripping of the McNary units

  - reduced reactive support to the COI resulting from loss of McNary units and nonparticipation of Coyote Springs, and Hermiston

In addition, the response of the PDCI to system voltage swings may have contributed to growing oscillations.

5. WIDESPREAD LOSS OF GENERATION AND LOAD.

   - The loss of the COI (which also occurred on July 2) resulted in approximately 28,000 MW of underfrequency load shedding and approximately 20,000 MW of undesired generation loss in the northern California and southern islands in this disturbance.

In summary, the disturbance could have been avoided, in all likelihood, if contingency plans had been adopted to mitigate the effects of the Keeler-Allston 500-kV line outage. Inadequate tree-trimming practices, operating studies, and instructions to dispatchers also played a significant role in this disturbance.

ISLANDS

The disturbance created four electrical islands:

1. Northern California Island (north of Los Angeles extending to the Oregon border)
   - Created by: loss of the COI, Midway-Vincent out-of-step tripping, tripping of the PG&E-SPP ties
   - Load lost: 11,602 MW (388,017 MW-minutes) - due to manual and automatic underfrequency load shedding
   - Generation lost: Over 40 units totaling 7,937 MW due to loss of excitation from low voltage and out-of-step conditions, turbine-generator vibration, antimotoring and line trips
   - Customers affected: 2,892,343
   - Frequency: dipped initially to 58.54 Hz, spiked to 60.7 Hz, dropped again to 58.3 Hz, and returned to normal in two and a half hours

2. Southern Island (southern California; southern Nevada; Arizona; New Mexico; El Paso, Texas and northern Baja California)
   - Created by: out-of-step tripping between Utah/Colorado and Arizona/New Mexico/Nevada and out-of-step tripping between Midway and Vincent and tripping of the SCE-SPP 55-kV ties
   - Load lost: 15,820 MW, (1.98 million MW-minutes) due to automatic and manual underfrequency load shedding
   - Generation lost: Over 90 units totaling 13,497 MW due to loss of excitation, boiler instability, overcurrent, underfrequency, flame failure, overfrequency and line trips
   - Customers affected: 4,195,972
   - Frequency: spiked to 61.3 Hz, dropped to 58.5 Hz, returned to normal in 70 minutes

3. Northern Island (British Columbia, Oregon, Washington, Montana, Wyoming, Idaho, Utah, Northern Nevada, Colorado, western South Dakota, and western Nebraska)
   - Created by: loss of COI, BCHA/TAUC separation, tripping of PG&E-SPP ties, SCE-SPP ties, and Utah/Colorado-Arizona/New Mexico/Nevada ties
   - Load lost: 2,099 MW (95,075 MW-minutes) due to loss of transmission
   - Generation lost: 60 units totaling 5,689 MW, due to activation of the Pacific AC and DC Intertie remedial action schemes, overfrequency, or loss of excitation due to low voltage
   - Customers affected: 209,858
   - Frequency: increased to 60.4 Hz, returned to normal in 17 minutes

4. Alberta Island (Alberta)
   - Created at 1554:36 by: generation in Alberta ramped back due to high frequency, overloading and tripping the BCHA/TAUC interconnection.
   - Load lost: 968 MW (24,888 MW-minutes, due to automatic underfrequency load shedding
   - Generation lost: six units totaling 146 MW due to overfrequency
   - Customers affected: 191,904
   - Frequency: increased to 60.4 Hz, then dropped to 59.0 Hz and returned to normal within six minutes

TOTAL WSCC IMPACTS:
Load lost: 30,489 MW
Generation lost: 27,269 MW
Customers affected: 7.49 million
Load not served: 2.48 million MW-minutes

II. CONCLUSIONS AND RECOMMENDATIONS

All recommendations will require a response to WSCC by the indicated date and denote the party responsible for reporting. The WSCC will track progress on each recommendation. The WSCC Board of Trustees will be responsible for ensuring that all recommendations are implemented in accordance with the schedule. Target completion dates are indicated in parentheses following each recommendation.

1. **Conclusion:** System operation was not in compliance with the WSCC Minimum Operating Reliability Criteria (MORC) prior to the outage of the Keeler-Allston 500-kV line. Outage of the Keeler-Allston 500-kV line precipitated the overloading and tripping of parallel lines, voltage drops, the undesirable tripping of key hydro units, and subsequent increasing oscillations, all of which led to tripping the COI and other major lines, and separating the system into four islands, causing the widespread uncontrolled outage of generation, and interrupting electric service to approximately 7.5 million customers.

   The following are excerpts from the WSCC MORC and the WSCC Reliability Criteria for Transmission System Planning:

   > "... Member Systems shall establish interarea transfer capability limits for conditions representing the outage of any of the facilities that affect the transfer capability limits."
   >
   > "The systems or control areas will remain stable upon loss of any one single element without system cascading that could result in the successive loss of additional elements."
   >
   > "Systems or control areas should immediately take steps to . . . ensure that loss of any subsequent element will not violate the transfer capability limit criteria."
   >
   > "During an emergency condition, security and reliability of the bulk power system are threatened; therefore, immediate steps must be taken to provide relief . . . Loss of Any Element - The system(s) causing the emergency condition shall take immediate steps to relieve the condition by adjusting generation, changing schedules between control areas, and initiating relief measures including manual or automatic load shedding (if required) to relieve overloading or imminent voltage collapse."
   >
   > "The Criteria does not permit any uncontrolled loss of generation, load, or uncontrolled separation of transmission facilities."

Recommendation:

a. BPA shall assess why it failed to identify that a Keeler-Allston 500-kV line outage would overload parallel lines, and potentially violate the WSCC MORC. BPA shall immediately implement corrective action as appropriate. BPA's assessment and mitigating actions (e.g., operating procedures, training, studies, etc.) that have been or are being taken shall be submitted to WSCC's Compliance Monitoring and Operating Practices Subcommittee (CMOPS). (December 1996)

b. Northwest Power Pool members shall reassess their operating policies, practices, and procedures to ensure that the Northwest bulk power system is operated in compliance with WSCC and NERC criteria and procedures in light of the August 10 and July 2 disturbances and report to CMOPS. (December 1996)

2. **Conclusion:** The outage of the Keeler-Allston 500-kV line overloaded the four parallel lower voltage lines. PAC's Merwin-St. Johns 115-kV (by relay misoperation) and BPA's Ross-Lexington 230-kV lines subsequently tripped and the remaining two PGE 230-kV lines loaded to 150 percent of their emergency rating. PGE's parallel 230-kV lines were overloaded (for approximately seven minutes) after the loss of the Keeler-Allston 500-kV line. These outages and overloads caused a voltage drop in the Hanford area, in turn causing the McNary generating units to increase their reactive power output — already at the maximum sustainable level.

Recommendation:

a. The WSCC Operations Committee (OC) and Planning Coordination Committee (PCC) shall thoroughly review WSCC's and its members' processes for studying upcoming system operating conditions and implement any changes for WSCC processes and recommend changes for members' processes as needed to ensure that these processes for identifying all critical and unusual operating conditions are adequate, and that credible disturbances are adequately studied prior to encountering them in real-time operating conditions. (March 1997)

b. The WSCC OC shall develop a process for reporting on anticipated operating conditions, critical conditions, and the results of studies conducted to assess these conditions. (March 1997)

c. BPA shall review and report to CMOPS regarding procedures for identifying and accounting for critical operating conditions and implement appropriate corrective measures. (December 1996)

d. WSCC's Security Process Task Force (SPTF) shall pursue implementation of on-line power flow and security analysis, and recommend appropriate actions to increase the monitoring of key system parameters that would allow operators to identify potential problem outages and take corrective actions. (December 1996)

e. All WSCC members shall provide the data requested by other members required for system monitoring and on-line security programs. In conjunction with NERC SPTF requirements, the data shall be exchanged by April 1997.

f. The WSCC Dispatcher Training Subcommittee (DTS), in conjunction with BPA, PGE, and PAC shall evaluate and report to CMOPS whether the dispatcher response to the Keeler-Allston outage was proper and recommend appropriate actions. (December 1996)

g. BPA shall ensure, and report to CMOPS, that its dispatchers are trained and have appropriate guidelines regarding actions to be taken when they encounter stressed or unusual operating conditions for which there are no prescribed operating instructions. The WSCC Dispatcher Training Subcommittee shall similarly develop generic guidelines for all WSCC members. (December 1996)

h. The WSCC PCC/OC Joint Guidance Committee shall review methodologies being used for off-line studies and develop a process that will reasonably ensure that all credible contingencies are considered both in rating studies and in operating studies. (December 1996)

i. The WSCC Intertie Study Group (ISG) shall investigate, and make appropriate recommendations regarding, the conditions of August 10, including increased system stress due to simultaneous transfers from British Columbia to the Northwest and from the Northwest to California and determine the impact that the Canadian transfers had on the severity of this contingency. The effects of Montana-Northwest and Idaho-Northwest (in both directions) transfers shall also be studied. (December 1996)

j. The Northwest Power Pool (NWPP) Transmission Planning Committee (TPC) shall investigate and determine appropriate operational limits for several portions of the I-5 corridor between Seattle and Portland, including the Keeler-Allston cut plane. This cut plane shall include appropriate transmission lines on the west and east sides of the Cascades. (May 1997)

   Status: The Seattle-Portland (SeaPort) study group was formed by the NWPP-TPC to review critical paths along the I-5 corridor between Seattle and Portland associated with the 3,150 MW BCHA-to-Northwest path uprate planned for completion in 1997. This planning study was agreed upon by BPA, PGE, and PAC to facilitate acceptance of the WSCC Facilities Rating process Phase III status of the BCHA-to-NW uprate. Participation in this study group was open to all interested parties. One portion of these studies focused on the Keeler-Allston 500-kV outage and potential overloads on the underlying transmission lines. The report on the Keeler-Allston path was presented to the SeaPort group in May 1996. Shortly thereafter, a presentation was also made to the NWPP-TPC. The effort to compile all of the sections of the study into a comprehensive report was in progress at the time of the August 10 disturbance. This comprehensive report was not yet available to the NWPP-TPC or the WSCC. Following the August 10 disturbance, an evaluation is being done, factoring in additional generation patterns on the existing system as well as the future system.

3. **Conclusion:** A wide variety of conditions and contingencies must be looked at to ensure that the system is planned and operated within the WSCC Reliability Criteria. Nevertheless, it is recognized that improbable conditions can develop that will lead to system separation across major transfer paths, such as the COI and other paths.

   Recommendation: The Technical Studies Subcommittee (TSS) shall report (to PCC) to what extent studies have been run to determine the consequences of loss of the COI and other critical paths and what mitigative measures are in place to minimize the consequences of such disturbances. (December 1996)

4. **Conclusion:** Immediately following the loss of the Ross-Lexington 230-kV line and the Merwin-St. Johns 115-kV line, the McNary units began tripping due to excitation system protection problems, withdrawing substantial real, reactive, and inertial support from the system. Three McNary units also tripped prior to COI separation during the July 2 disturbance and were identified in the disturbance review.

   Recommendation:

   a. USCE shall review and report to CMOPS whether exciter protection at McNary was proper on both July 2 and August 10, identify why the McNary units tripped and take appropriate action so that undesirable unit tripping will not occur. (December 1996)

      Status: On August 16 and August 17, work was completed to adjust the McNary voltage regulators for units 1-12 and 14. The WSCC Intertie Transfer Capability Policy Committee will review corrective measures. Work is also underway to change taps on all 13.8/230-kV transformers at the McNary powerhouse to increase the 230-kV voltage. Testing underway suggests the problem was false tripping of the phase imbalance relay on the exciter system. By September 11, most testing and corrections were completed at McNary powerhouse. Replacement parts for the faulty relay have been ordered and modifications will be completed in November 1996.

   b. USCE shall review and test their generating unit exciters in the Northwest to ensure proper operation of exciter controls and protection. Results should be properly modeled by BPA in system studies and actions taken by BPA and USCE reported to CMOPS. (December 1996)

c. The WSCC Control Work Group (CWG) shall determine what tests need to be applied to generating unit exciters to ensure proper operation of exciter controls and protection. They shall also determine what unit MVA level must be tested and develop a procedure to ensure uniform testing, including the frequency of testing and a recommended priority list of units to be tested first. (The CWG work must be completed by November 1, 1996.) All generation owning and operating entities in the WSCC region shall perform the prescribed testing and report to CMOPS. (June 1997) The results should be used to properly model generating units in system studies, and actions taken reported to CMOPS. (June 1997)

d. The WSCC ISG shall determine the effect of the McNary and other Northwest units on system dynamic and voltage stability. (December 1996)

e. Conclusion 1, recommendation a of the July 2, 1996 disturbance report states "Idaho Power Company, PacifiCorp, Bonneville Power Administration (BPA), and other Northwest area entities shall reduce scheduled transfers to a safe and prudent level until studies have been conducted to determine the maximum simultaneous transfer capability limits and to thoroughly evaluate operating conditions actually observed on July 2." BPA shall determine and report to CMOPS why McNary problems were not considered in establishing new COI, BCHA-NW, and other operating limits following the July 2 disturbance and prior to the August 10 disturbance. (October 1996)

f. BPA shall also determine why corrective measures at McNary were not implemented prior to increasing AC Intertie operating limits after the July 2 limits were imposed and report to CMOPS. (October 1996)

g. BPA, USPN and USCE shall ensure that transmission planning models are accurate and reflect the up-to-date capability of the system. (October 1996)

h. BPA, USCE, and USPN shall review the adequacy of their inter-organizational communications and shall jointly plan and initiate corrective actions to their respective systems to ensure reliable operation. (October 1996)

5. **Conclusion:** During the tripping of the McNary units, 0.2-Hz power system oscillations were initiated and increased in magnitude.

Recommendation:

a. The WSCC ISG shall investigate the cause of the undamped oscillations and make recommendations. (December 1996)

b. The WSCC CWG shall review the number of power system stabilizers (PSS) in service at the time of the disturbance and make appropriate recommendations. (March 1997)

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c. The WSCC ISG shall determine whether high levels of excitation made PSS ineffective and make appropriate recommendations. (March 1997)

d. The WSCC CWG shall review the application and settings of PSS to determine adequacy and make appropriate recommendations. (March 1997)

e. The WSCC Technical Studies Subcommittee (TSS) shall review the feasibility and desirability of implementing other oscillation damping controls, such as high voltage direct current (HVDC) modulation and make appropriate recommendations. (June 1997)

f. All WSCC owners of generators, in conjunction with the WSCC TSS and CWG shall assess whether installed excitation systems and PSS on units with capacity of ten MW or larger, are properly tested, tuned, and correctly modeled in transient stability studies and make appropriate recommendations. (March 1997)

6. **Conclusion:** COI operational limits, and any misjudgment in establishing those limits, can have a profound effect on the entire WSCC Interconnection. Although the COI operating limits and associated high transfers were not the root cause of the disturbance, they contributed to the overall severity of the disturbance. At the time of the August 10 disturbance, the COI schedule was 4,285 MW and actual flow was 4,350 MW. The operating limit at the time (based on the nomogram) was 4,740 MW. The operational limit in place at the time of the disturbance had been developed by BPA, PG&E, IPC, and PAC after the July 2 disturbance, with only cursory review by other WSCC parties.

Recommendation:

a. WSCC shall form an Intertie Transfer Capability Policy Committee to ensure that NW imports/exports, including COI, Midpoint-Summer Lake, BCHA-NW, NW-Montana and other transfer levels are maintained at safe levels. They shall have the authority to raise or lower operational limits. As agreed upon at the August 12 emergency meeting of the WSCC Executive Committee, approval shall be required from the Intertie Transfer Capability Policy Committee to exceed north to south transfer levels of 3,200 MW at the California-Oregon Border. Subsequent technical discussions led to allocating a north to south limit on the Pacific HVDC Intertie (PDCI) of 2000 MW unless the Midpoint-Summer Lake 500-kV line flow exceeds 200 MW into Summer Lake, at which point the PDCI may be loaded to 2200 MW. A WSCC-wide process using the WSCC Intertie Study Group and the Intertie Transfer Capability Policy Committee shall be developed and implemented for the interim review of changes to operating procedures and operating limits affecting the Northwest interconnected system. This review function is for operational limits and shall not replace WSCC's established project rating review process and shall not be used to establish ratings higher than those currently existing. This process shall be expanded to encompass all major WSCC transfer paths. (October 1996)

b. The WSCC ISG shall identify and report to CMOPS the operating practices needed to ensure that credible generation and transmission outages within the Interconnection do not result in the loss of the California-Oregon Intertie. The WSCC members shall implement revised operating practices as appropriate. (April 1997)

7. **Conclusion:** In the hour and a half prior to the disturbance, BPA's Big Eddy-Ostrander, John Day-Marion, and Marion-Lane 500-kV lines were forced out of service. Local load area voltage adjustments were made; however, no vulnerabilities were identified by BPA dispatchers and no changes were made to interarea transfers or internal line loadings to reduce system stress. It is not yet known to what degree these outages contributed to the severity of the disturbance. No BCHA-NW or other COI limits had been identified in relation to these outages. Had a need for limits related to these line outages been identified, ample time was available to make system adjustments.

Recommendation:

a. BPA shall determine what tools and information are needed to recognize and deal with potential system problems such as those experienced on August 10, and ensure that its operators are informed and trained to respond to such operating problems. BPA shall ensure that operating procedures are in place to mitigate potential operating problems before they escalate and cause reliability problems. BPA's actions shall be reported to CMOPS and the WSCC SPTF. (December 1996)

b. WSCC's Intertie Study Group shall investigate the impact of the Big Eddy-Ostrander and John Day-Marion-Lane line outages. This investigation shall determine whether the Keeler-Allston and/or Keeler-Pearl line outage would have overloaded the Ross-Lexington 230-kV, PacifiCorp's Merwin-St. Johns 115-kV and PGE's 230-kV Trojan lines or resulted in voltage collapse if these three lines had still been in service. (December 1996)

c. BPA shall implement various off-line, on-line, and real-time monitoring tools to identify at-risk system operating conditions. (Report status to CMOPS by December 1996 and implement by June 1997)

8. **Conclusion:** While the outage of the Big Eddy-Ostrander 500-kV line was known to PGE and the John Day-Marion 500-kV line outage was known to PG&E by inter-utility data exchange, the three 500-kV line outages experienced by BPA during the hour and a half prior to the disturbance were not reported to other WSCC members, precluding their ability to take mitigating actions had they perceived a need for such action.

Excerpt from the WSCC Procedure for Coordination of Scheduled Outages and Notification of Forced Outages:

"A. Each WSCC Member System which owns or operates a key generation or transmission element scheduled to be removed from service or which has been forced out of service is responsible for notifying the other WSCC members via the WSCC Communication System of the facility outage. Key facilities are those which are considered important to interconnected system operation by the system which owns the facilities. Key facilities generally include:

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3. Transmission operated at 230-kV and higher that can significantly affect interarea system operation ... "

Up to this time, BPA had not considered the named lines as key facilities for reporting.

Recommendation:

a. CMOPS shall review WSCC's policies, procedures, and criteria for reporting key facility outages (considering that lightly loaded lines are an important source of VARs and provide system support during disturbances) and implement improvements and eliminate ambiguity in reporting requirements. This review shall include lower voltage lines similar to those out of service on the BPA system prior to the August 10 disturbance and should address key generating facilities as well. (December 1996)

b. BPA shall review its criteria for designating key facility outages for reporting and indicate why the lines were not designated as "key" facilities and why the outages prior to the disturbance were not widely reported to other WSCC members. (December 1996)

c. BPA shall ensure its system operators are trained to recognize and report critical and abnormal system conditions and key facility outages to WSCC, and shall develop appropriate tools, such as on-line power flow, to aid in these assessments. (December 1996)

9. **Conclusion:** On August 10, the Big Eddy-Ostrander, John Day-Marion 500-kV, Keeler-Allston 500-kV, and Ross-Lexington 230-kV lines were faulted due to conductors flashing over to trees in the right-of-way. All of these outages are the result of inadequate right-of-way (ROW) maintenance by BPA. During the period from June 1 to August 9, a total of five 500-kV line outages (two of these were the same problem on the same line within 40 minutes), and two 115-kV line outages (both momentary outages on the same line within two days of each other) on the BPA system were caused by flashovers to trees. BPA has 4,447 miles of 500-kV, 5,233 miles of 230-kV, and 3,676 miles of 115-kV lines.

Recommendation:

a. BPA shall submit a copy of its tree-trimming and line-patrolling procedures as of August 10 to CMOPS, identifying what parts of the procedure had not been complied with (if any) as of August 10, including reasons for any noncompliance. Dollar amounts budgeted and actual expenditures for tree trimming for 1993 through 1996 shall also be provided. (September 1996)

b. BPA shall determine why the trees that resulted in the flashovers on the lines involved were not identified and removed or cut to design clearances prior to the incident on August 10 and report to WSCC. (September 1996)

c. BPA shall determine why identified danger trees were not removed and shall reevaluate procedures, environmental impacts, and legal requirements for removing danger trees affecting fire safety and reliability. (December 1996)

d. BPA shall report to WSCC what actions have been taken since August 10 to improve its tree-trimming procedures and describe any ongoing efforts to improve their effectiveness. (September 1996)

e. All transmission-owning member systems shall review their tree-trimming programs to ensure that they are adequate and shall provide information to WSCC that indicates any changes (including budgeted monies) made to the programs over the past two years and/or that are intended to be made in the near future. (September 1996)

f. All transmission owning members shall evaluate the need for changes in the tree- trimming policies of the U.S. Forest Service and other federal land agencies and submit recommended enhancements to WSCC. Canadian and Mexican members shall evaluate the need for change in their respective jurisdictions. (December 1996)

10. **Conclusion:** The system oscillations increased until voltage finally collapsed on the COI, leading to the COI opening and the subsequent formation of four islands in the WSCC. Generating units in the Northwest (such as Hermiston, and Coyote Springs) did not respond dynamically or in the steady state with reactive support as predicted in studies. The level of dynamic reactive support from generation at the northern terminus of the COI and PDCI has been greatly reduced by fish operation constraints, particularly at The Dalles.

Recommendation:

a. By November 1997, the WSCC CWG shall determine what tests should be applied to generating units to determine their steady state and dynamic reactive capabilities and provide appropriate guidelines. They shall also determine what unit MVA level must be tested and develop a procedure to ensure uniform testing, including the frequency of testing, and a recommended priority list of units to be tested first. (The CWG work must be completed by November 1, 1996.) Generation-owning and operating entities in WSCC shall test, or provide proof of tests on, their generating units with capacity of ten MW or greater to determine their steady state and dynamic reactive capabilities, adjust study assumptions to match the test results, and report to CMOPS. (June 1997)

b. BPA shall take into account fish spill requirements at The Dalles, John Day, McNary, and other Northwest hydro generation plants when determining transmission capabilities. BPA shall report to CMOPS how this will be accomplished. Special attention shall be given to the loss of dynamic reactive reserves from these plants. (December 1996)

c. BPA shall report to CMOPS regarding actions taken to ensure that instructions to system operators relating to the reactive requirements of the system under various contingency conditions are adequate. These instructions shall include actions required to mitigate the loss of reactive margin, such as bringing generating units on line, switching shunt devices, reducing schedules and line loadings, and manually shedding load. (December 1996)

d. The WSCC PCC/OC Joint Guidance Committee shall review the recommendations made in the NERC publication entitled "Survey of the Voltage Collapse Phenomenon" and make appropriate assignments to review the recommendations and ensure that they have been appropriately implemented within the Western Interconnection. (June 1997)

e. The WSCC PCC shall develop reliability criteria for reactive reserves and reactive margin. (December 1996)

f. Generation-owning and operating entities in WSCC shall ensure that generating units will provide proper steady state and dynamic voltage support, through actions such as keeping voltage regulators on automatic voltage control. The MORC Work Group shall develop suitable modifications to the criteria, including criteria relating to constant power factor control. Results shall be reported to CMOPS. (June 1997)

g. BPA and all other control areas shall perform reactive margin studies for worst case scenarios and report study results to the WSCC OC. (June 1997)

h. PGE, PAC, and USCE, in conjunction with the WSCC ISG shall determine and report to CMOPS the extent to which Coyote Springs and Hermiston generation were or were not providing effective voltage control and reactive support in the McNary area during this disturbance and make recommendations as appropriate to enhance system performance. (December 1996)

i. The WSCC ISG shall determine whether circuit outages in the Portland area impacted the simultaneous transfer capability of the COI and other paths to the Northwest. (December 1996)

j. BPA, USPN and USCE shall determine and report to CMOPS how plant reactive power may be increased by considering options such as operating units in condensing mode or with more units on line for a given power level (reduced efficiency), or other alternatives. (December 1996)

k. The WSCC TSS shall respond to regulatory questions about the use of flexible AC transmission system (FACTS) devices and other voltage support devices to enhance system performance and make recommendations to the PCC. (June 1997)

l. The WSCC ISG shall develop nomograms for Northwest Intertie operations, including the COI, PDCI, BCHA, Idaho, Montana, and other transfer paths, that will ensure reliable operation. Such nomograms shall consider the generation availability and load level of the Northwest. BPA shall provide information to WSCC illustrating actual flows relative to the nomograms on a daily basis until such reporting is no longer deemed necessary. (December 1996)

m. The WSCC member systems shall evaluate the need for and report to WSCC regarding the application of undervoltage load shedding on their individual systems to enhance interconnected system reliability. (March 1997)

11. **Conclusion:** Boardman coal plant responded dynamically to the loss of the Keeler-Allston 500-kV line, increasing its reactive output to 157 MVAR at Slatt, but backed down to 78 MVAR, by operator intervention, after approximately 30 seconds.

    Recommendation: PGE shall determine whether the response of Boardman to this disturbance was proper. (November 1996)

12. **Conclusion:** Special operations to protect fish (such as reducing generation and increasing spill at The Dalles) reduced the amount of real power, reactive power, and inertial support provided to the system, and therefore adversely impacted system reliability.

    Recommendation: The WSCC ISG shall model these special fish-protecting operations in the studies they are conducting to determine the impact on COI transfer capability, paying particular attention to the loss of reactive power support due to these operations. The WSCC ISG shall report its findings and recommendations to CMOPS. (April 1997)

13. **Conclusion:** On August 10, temperatures were high throughout much of the WSCC region. As a result, loads in some areas were very high for a Saturday, including air conditioning induction motor loads. These load characteristics may have had a significant effect on the nature and severity of the disturbance.

    Recommendation: The WSCC ISG shall determine and report to WSCC regarding the impact of load levels and load characteristics on this disturbance and make appropriate recommendations to enhance study capabilities, improve system models, and improve system performance. (June 1997)

14. **Conclusion:** Upon opening of the COI, the Northern California and Southern Islands lost nearly 28,000 MW of load and approximately 20,000 MW of generation. A similar separation occurred on the COI on July 2, 1996. In a generation deficient condition, the intended outcome is for only load to trip. Unlike the July 2 disturbance, in this instance, system performance in the Northern California and Southern Islands was adversely affected by the uncontrolled tripping of a substantial amount of generation.

    Recommendation:

    a. Generation owning entities that lost generation in the low frequency islands shall report to the Relay Work Group the reasons for units tripping and any corrective actions taken since August 10. (October 1996)

    b. The WSCC Relay and Control Work Groups shall determine why actions taken in response to the December 14, 1994, system disturbance were not effective in preventing the uncontrolled loss of generation on August 10 and recommend corrective actions. (March 1997)

    c. The WSCC CMOPS shall determine why the frequency could not be restored without manual load shedding after extensive underfrequency load shedding and make appropriate recommendations. (March 1997)

    d. All WSCC members, or groups of members, experiencing low frequency in this disturbance shall analyze whether operation of underfrequency load shedding systems was proper and appropriately coordinated among entities within each island. Deficiencies shall be reported to WSCC and corrective measures implemented. (December 1996)

       Status: Three of the six load banks (with a load of 154 MW at the time of the disturbance) in LDWP's 58.5 Hz underfrequency load shedding block failed to trip. An underfrequency relay on one of the banks was found to be defective and replaced. The relays on the other two banks were tested and found to be set within tolerance (58.49 Hz) and operating properly. These relays apparently did not trip because the frequency was not low enough for long enough to activate them.

    e. The WSCC OC shall initiate a study to review the coordinated underfrequency load shedding programs on a subregional and regional scale. The coordination of underfrequency load shedding with underfrequency generator protection shall be included in the study. Recommendations shall be developed and implemented. (June 1997)

15. **Conclusion:** Colstrip Units 1, 3, and 4 tripped by Acceleration Trend Relay action during the disturbance.

Recommendation: MPC shall determine and report to CMOPS whether Colstrip tripping was appropriate and take corrective action if needed. (December 1996)

16. **Conclusion:** At the time of the August 10 disturbance, the Northeast/Southeast Separation Scheme was out of service in accordance with the WSCC Committed Action Plan Agreement. The power system separated on out-of-step across the NE/SE boundary 1-2 seconds after it would have separated had the scheme been in service. It is possible that the faster, more coordinated separation provided by the scheme could have lessened the impact of this disturbance in the Southern Island.

    Recommendation: The WSCC ad hoc Controlled Islanding Work Group shall study the impact on this disturbance of not having the NE/SE Separation Scheme in service and make appropriate recommendations. This study shall also consider direct load tripping in the southern island and the northern California island as remedial action for loss of the COI and the negative impact of a false operation of the NE/SE Separation Scheme. (June 1997)

17. **Conclusion:** The NE/SE Separation Scheme was placed in service at 0101 PAST on August 11, 1996, after some discussion among the major participants in the scheme. This scheme had been out of service since the completion of the California-Oregon Transmission Project (COTP) except under certain loading conditions and when the COTP is out of service. Notification was posted by APS on the WSCC Communication System. However, SPP was not informed by PG&E of the change in accordance with procedures and did not enable its part of the scheme until about three days later.

    Recommendation:

    a. The WSCC OC shall review the procedure for notification of status changes for this scheme and make appropriate changes. Operating and planning engineers shall also be notified to ensure that future changes in status of the scheme are properly coordinated. (March 1997)

    b. The WSCC OC shall evaluate a means to include feedback in the notification process to ensure notifications have been received and read. (March 1997)

    c. PG&E shall review and report to CMOPS regarding procedures to ensure appropriate communication of changes in status of the NE/SE Separation Scheme. (October 1996)

    d. SPP shall report to CMOPS why it did not act upon the WSCC message informing members of the NE/SE Separation Scheme activation.

    e. The PCC/OC Joint Guidance Committee shall determine whether it is prudent to continue with the NE/SE Separation Scheme in service and make appropriate recommendations. (November 1, 1996)

18. **Conclusion:** Multiple transmission paths opened by out-of-step relay action, separating the main WSCC loop into four electrical islands.

    Recommendation: The WSCC ad hoc Islanding Work Group shall investigate and report to CMOPS the contributing causes of the separations and recommend appropriate actions to enhance system performance. (March 1997)

19. **Conclusion:** Governor response to high frequency resulted in increased flows into Alberta from British Columbia. Five minutes into the disturbance, the increased flow caused low voltage and high current which resulted in the tripping of the interconnection between BCHA and TAUC.

    Recommendation:

    a. BCHA and TAUC shall evaluate why the tie tripped, take appropriate action and report to CMOPS. (October 1996)

    b. TAUC and BCHA shall determine and report to CMOPS whether governor response was appropriate and implement any necessary corrective measures. (October 1996)

20. **Conclusion:** The frequency stayed high in the Northern Island (about 60.4 Hz for fourteen minutes, crossing 60 Hz after seventeen minutes). After returning to 60 Hz, the frequency rose again to 60.04 Hz and remained there for 50 minutes. Despite having no direct schedules to California, BCHA unilaterally cut schedules by approximately 600 MW to reduce island frequency, absorbing 2,200 MWH of inadvertent interchange over the next three hours.

    Recommendation:

    a. The WSCC CMOPS shall determine why frequency did not return to normal in a timely manner and recommend corrective action. (December 1996)

    b. BPA, PAC, BCHA, PSPL, PGE, and other Northwest island parties shall evaluate and report to CMOPS the role scheduling played in keeping the frequency high. The parties shall determine what schedules, if any, were not cut that should have been. (December 1996)

    c. The WSCC SPWG shall review and report the process for rapid changes of schedules on the COI and PDCI. They shall determine the required time for operator initiated emergency schedule changes and the effectiveness (system response in time, MW, and frequency) of those changes. (December 1996)

21. **Conclusion:**

    Southern Island frequency was below 59.0 Hz for twenty minutes and below 60 Hz for over an hour.

Northern California Island frequency hovered around 59.5 Hz for 75 minutes. Automatic load restoration impeded frequency restoration in the Northern California Island. Low frequency in the Southern and Northern California Islands impeded the restoration process by preventing synchronization of any two islands.

Recommendation:

a. All member systems shall review and report to CMOPS regarding the problems associated with coordination of automatic and manual load restoration and take appropriate action. (March 1997)

b. CMOPS and the WSCC SPTF shall review the role and authority of the WSCC Coordinating Centers in facilitating load restoration and develop recommendations as appropriate for improved performance. (December 1996)

c. Each island's utilities shall determine and report to CMOPS regarding any other factors that delayed the recovery of frequency and recommend corrective measures. (December 1996)

22. **Conclusion:** Protective relays on critical lines appeared to have operated properly with the exception of the Merwin-St. Johns 115-kV line, which was tripped by a malfunctioning zone 1 KD relay.

    Recommendation: PAC shall investigate this relay misoperation, take corrective action and report to CMOPS. (November 1996)

23. **Conclusion:** The Keeler SVC tripped 1.5 seconds after the COI separation by undervoltage relaying. LDWP similarly lost PDCI Converters 1 and 2 at Sylmar when their cooling systems tripped after the Sylmar voltage dropped to 0.68 pu. LDWP also lost SVCs at Adelanto and Marketplace because of low voltage.

    Recommendation:

    a. BPA shall investigate and correct the problem that tripped the Keeler SVC and shall report its findings and actions to CMOPS. (March 1997)

    b. LDWP shall investigate and correct the problems causing the loss of the Sylmar DC auxiliary systems and system SVCs and report its findings to CMOPS. (March 1997)

    c. Under the direction of CMOPS, all WSCC members shall review their own SVCs and any other critical, voltage-sensitive power system equipment to determine if they may have similar problems and implement corrections as required. (March 1997)

24. **Conclusion:** The PDCI power levels fluctuated substantially in response to changing AC voltage.

    Recommendations:

    a. BPA and LDWP shall determine and report to CMOPS as to whether the HVDC response, including the actions of protection systems that reduced the DC capacity, was appropriate and/or contributed to the severity of the disturbance and shall take action as appropriate. (December 1996)

    b. The WSCC ISG shall review and report to CMOPS as to whether the PDCI response during the oscillations was a contributing source of negative damping and reduced synchronizing power and make appropriate recommendations. (December 1996)

25. **Conclusion**: LDWP manually blocked the PDCI due to the uncontrolled loss of equipment and an excessive (1,000 MVAR) converter reactive power draw from the AC system at Sylmar. This may have contributed to manual load shedding in the Southern Island.

    Recommendation: LDWP shall assess and report to CMOPS the appropriateness of interrupting imports through the PDCI while in a low frequency island and correct procedures if necessary. (October 1996)

    Status: The LDWP senior load dispatcher was fully aware of the implications of blocking a source of import power into a low frequency island when he made the decision to do so. The LDWP dispatcher decided to block the PDCI because he believed the excessive reactive power demand at Sylmar, coupled with the uncontrolled loss of PDCI equipment over the previous ten minutes (and the perceived threat of additional uncontrolled loss of equipment) was a greater threat to the security of the island than was the loss of the power being imported.

26. **Conclusion:** WAPA lost the two Glen Canyon-Flagstaff-Pinnacle Peak 345-kV lines when the Pinnacle Peak 345/230-kV transformers opened due to overexcitation. The Glen Canyon end of the lines subsequently opened due to high voltage resulting from the line charging of the open-ended lines. The transformer overexitation condition lasted for nearly two hours, resulting in the unavailability of Glen Canyon generation, though it was critically needed as a resource during recovery from the disturbance.

    Recommendation:

    a. WAPA shall test the transformer overexcitation relays, review relay settings, implement appropriate corrective measures and report to CMOPS. (October 1996)

b. WAPA shall investigate and report to CMOPS regarding the cause of the lines that tripped, isolating the Glen Canyon plant from the power system, and implement appropriate corrective measures. (October 1996)

27. **Conclusion:** The first COI line was restored at 1818 PAST, but schedules on this path were not resumed until the hour ending 2100 PAST. The delay hampered load restoration efforts in the Northern California Island. (Remaining interconnections were also restored in this period.)

    Recommendation: PG&E and BPA shall determine and report to CMOPS the cause of the delay in resuming scheduling and take appropriate action. (October 1996)

28. **Conclusion:** Several control centers including APS, WAMP, TEP, TNP, and SRP lost their Energy Management Systems (EMS) during the disturbance. The Uninterruptible Power Supply (UPS) at APS failed and the EMS was down for just over an hour. TNP lost its EMS computer, apparently due to alarm management problems. SRP lost its EMS three times during the disturbance. WAMP lost its EMS due to failure of its backup power supply system. It also lost communications, and PG&E was unable to contact WAMP to request additional generation. USPN lost its SCADA system at Grand Coulee, hampering efforts to control local circuit breakers and other critical facilities. Additionally, PAC lost its Portland EMS due to UPS failure, but continued operations through its back up control center.

    Recommendation: The WSCC EMS Work Group and utilities that experienced trouble with their control centers shall determine and report to CMOPS the causes of these failures and take appropriate corrective action. (December 1996)

29. **Conclusion:** Within 30 minutes after the disturbance began, the WSCC office was receiving calls from news media reporters demanding information about the disturbance. The WSCC Staff was unable to provide answers, not having been notified that a disturbance was in progress. Dispatchers were receiving calls directly from the news media, distracting them from system operations. The media representatives had reportedly received the dispatchers' phone numbers from the utility's security personnel and/or from other utilities. A significant problem during emergencies is phone calls unrelated to determining the problem and restoring the system.

    Recommendation:

    a. The four Coordinating Centers shall develop procedures to notify WSCC staff no more than ten minutes after a major disturbance is confirmed and provide known information. (October 1996)

    b. WSCC members shall develop and implement procedures for reporting system disturbance information on the WSCC Communication System within thirty minutes to allow all parties to assess conditions and develop an optimal response to the disturbance. (October 1996)

c. All member systems shall have policies in place to ensure dispatch phone numbers are not revealed to the public or news media without *prior* permission of the utility. (October 1996)

d. CMOPS shall develop a requirement within MORC specifying the minimum technical and executive resources which will be available 24 hours per day for system emergencies. (December 1996)

e. All WSCC members shall provide their operating management's (up to Council Representatives) cellular phone numbers and home phone numbers to the WSCC staff for use in coordinating the collection and dissemination of information regarding large scale system disturbances in the WSCC region. In addition, the WSCC staff shall compile a list of control center phone numbers. (October 1996)

f. The WSCC staff shall implement procedures to issue its initial press release to the members within thirty minutes of notification and to the media within one hour of notification of a large scale system disturbance in the WSCC region. (October 1996)

g. The WSCC staff shall have at least one cellular phone and a pager to be monitored continuously for use in coordinating the reporting of information regarding major system disturbances in the WSCC region. (October 1996)

h. The WSCC staff shall develop contingency plans for coordinating disturbance reporting information in the event the WSCC office is impacted by a disturbance. (June 1997)

30. **Conclusion:** Analysis of this disturbance was impeded by the lack of dynamic information at key points on the system, such as on the Midway-Vincent tie, west of Borah, the NE/SE cut plane, and other lines most likely to be involved in islanding or voltage collapse.

    Recommendation: The WSCC SPTF shall review the need for improved dynamic monitoring at key points and critical potential separation points in the system and shall make recommendations, including the time frame for implementation. Dynamic records shall be time tagged and include both pre-and/post-disturbance data. Key data shall be monitored to improve system security. (June 1997)

31. **Conclusion:** In response to this disturbance, utilities' energy traders, generation operators, and transmission operators found it necessary to coordinate closely to restore the system. As members restructure to comply with FERC Order 889, such close coordination may be limited.

Recommendation: The WSCC OC shall assess the potential impact of FERC Order 889, Standards of Conduct, on coordination between generation marketers/owners and transmission operators during disturbances and make appropriate recommendations to improve the coordination of system restoration. (March 1997)

32. **Conclusion:** The July 2 and August 10 disturbances emphasize the need for timeliness in the disturbance report recommendation resolution process. Examples of recommendations made as a result of previous disturbances that continue to be factors in more recent disturbances include the recommendations relating to controlled islanding, criteria for multiple contingencies, criteria for relay failures, and coordination of underfrequency load shedding.

    Recommendation: The WSCC Board of Trustees shall implement policies as needed to ensure that critical disturbance report recommendations are completed expeditiously. This includes ensuring adequate manpower and capital resources are available to implement these recommendations. (January 1997)

III. PREDISTURBANCE CONDITIONS

Most utilities had high Saturday loads as a result of hot summer temperatures in most of the western states prior to the disturbance. Flows on significant paths are listed in the following table.

Path	Rating	Flows	Percent of rating
Canadian Intertie between BCHA and BPA	2,300	2,300 MW North to South	100
California-Oregon Intertie	*4,800	4,350 MW North to South	91
Midpoint-Summer Lake	1,500	600 MW East to West	40
Pacific DC Intertie (at converter station)	3,100	2,850 MW North to South	92
Midway-Vincent	3,000	1,380 MW North to South	46
East of Colorado River Path	7,365	3,225 MW East to West	44
Northeast/Southeast Path	1,700	1,058 MW North to South	62

* Scheduling limit was 4740 MW due to the operating nomogram prepared after the July 2 disturbance.

Transmission lines out of service:

1. The Big Eddy-Ostrander 500-kV line tripped at 1406 PAST.
2 At 1452, the John Day-Marion 500-kV line tripped. Both the Big Eddy-Ostrander and John Day-Marion outages were caused by the lines flashing over to trees.
3. The John Day-Marion outage also forced out the Marion-Lane line due to system configuration (circuit breaker 4365 out of service).

Prior to these outages, the lines noted above were lightly loaded. The Big Eddy-Ostrander 500-kV line directly serves the Portland area. The John Day-Marion 500-kV line supports the Portland area from the south via the Marion-Pearl 500-kV line.

In addition to these outages, the Keeler 500/230-kV transformer was out of service for tap changer modifications and breaker replacement at Keeler. As a result, the Keeler +/-300 MVAR Static VAR Controller (SVC) was limited in its ability to support the 500-kV system.

In the Willamette Valley region, BPA had two 500-kV circuit breakers out of service for replacement: CB 4365 at Marion and CB 4322 at Keeler. The Allston terminal of the 115-kV St. Helens-Allston line was open due to the degraded thermal capability of this 115-kV line. Its use has been limited to radial operation. Generation at The Dalles was at reduced levels due to a 64 percent spill requirement for fish measures. Prior to the disturbance, no voltages or line loadings were in violation of established limits.

IV. DETAILED DESCRIPTION

DESCRIPTION OF DISTURBANCE

At 1548 PAST on August 10, 1996, a major disturbance hit the Western Interconnection, forming four islands. Conditions prior to the disturbance were marked by high summer temperatures (near or above 100 degrees) in most of the region, by heavy exports (well within known limits) from the Pacific Northwest into California and from Canada into the Pacific Northwest, and by the loss of several 500-kV lines in Oregon.

The COI North-to-South power flow was within parameters established by recent studies initiated as a result of the July 2 disturbance. The flow on the COI totaled approximately 4,350 MW; the power order on the PDCI was 2,848 MW.

EARLIER LINE OPERATIONS

At 1401 PAST, the Big Eddy-Ostrander 500-kV line relayed three-pole when it flashed to a tree. The PGE terminal of the Big Eddy-McLoughlin 230-kV line relayed and reclosed for this fault close to the Ostrander end. The Big Eddy-Ostrander line tested good and was returned to service at 1403. At 1406, the Big Eddy-Ostrander line relayed single-pole (A-phase), reclosed, tripped three-pole, and stayed out of service. PGE's terminal of the Big Eddy-McLoughlin 230-kV again relayed and reclosed. The 500-kV line had flows of 90 MW with 130 MVARs into the Big Eddy bus and 86 MVAR into the Ostrander bus. Around 1410, BPA SCADA logged low voltage alarms from Alvey (236-kV), Slatt (529-kV), Big Eddy (236-kV), and Vantage (239-kV). This low voltage was corrected by shunt reactor switching at the Grizzly 500-kV bus and by shunt capacitor switching at the Alvey 230-kV busses. At 1446, the Vantage 500/230-kV transformers were lowered one tap, bringing the Vantage bus voltage to 240-kV.

At 1452:37, the John Day-Marion 500-kV line relayed, reclosed, and tripped to lockout for a C-phase fault when it flashed over to a tree near Marion (tower 122/1). Due to Marion power circuit breaker (PCB) 4365 being out of service, this line outage also forced out the Marion-Lane 500-kV line. The John Day-Marion line tested bad at 1456. When it tripped, the John Day-Marion line was carrying 248 MW to Marion with 207 MVAR into the John Day bus and 35 MVAR into the Marion bus. The Marion-Lane line was carrying 330 MW and 105 MVAR. Following the loss of these lines, the Big Eddy bus alarmed at 235 kV and Slatt at 529 kV. Voltage control switching involved transformer tap changes at Allston and Big Eddy and the 500-kV shunt capacitors at Ostrander. At 1517, Slatt alarmed for below voltage schedule at 529 kV, as did Hanford at 525 kV.

INITIATING EVENTS

At 1542:37, fifty minutes after the John Day-Marion line fault, the Keeler-Allston 500-kV line, carrying 1,300 MW toward Keeler and 110 MVAR into Allston, tripped after flashing to a tree near Keeler. At the time, the current flow was 1,406 amps. The summer rating of this line is 2,900 amps. This also forced the Pearl-Keeler line out of service due to the Keeler 500/230-kV transformer being out of service. At this point, there were five 500-kV line segments out of service, removing several hundred MVAR of reactive support from the system and increasing the reactive requirement as other lines picked up the power flow from the lost lines. BPA SCADA systems received many voltage alarms in the mid-Columbia basin. McNary 500-kV bus, at 519 kV, dropped to 506 kV. The 230-kV bus alarmed at 237 kV (alarm set for 238 kV). Vantage was at 520 kV and the COI was 533-kV at Grizzly and Malin. Twenty and thirty seconds later, the Ross-Lexington 230-kV line alarmed at 1,235 amps (1,050 amp rating) and the Allston-Trojan line alarmed at 1,400 amps (1,315-amp emergency rating). BPA dispatchers requested maximum reactive power boost from John Day and The Dalles within one minute of the Keeler-Allston trip. Loading on the PGE Trojan-St. Marys and Trojan-Rivergate 230-kV lines increased from approximately 325 MW each (780 A) to 560 MW each (1,400 A, 106 percent of the PGE 1,315 A emergency rating). Loading on BPA's Ross-Lexington 230-kV line increased from approximately 330 MW (790 A) to 487 MW (1,237 A, 115 percent of its 1,070 A rating). Prior to the Keeler-Allston trip, the thirteen McNary generating units were producing 860 MW and 260 MVAR.

While the BPA system voltage situation was being assessed (BPA dispatchers were considering the possibility of COI schedule reductions), the Keeler-Allston line was tested from Allston and found bad at 1544 PAST. BPA dispatchers then called Washington Nuclear Power (WNP) Unit 2 (and other plants), requesting maximum reactive boost. Boardman coal plant responded dynamically to the loss of the Keeler-Allston 500-kV line, increasing its reactive output to 157 MVAR at Slatt, but backed down to 78 MVAR, by operator intervention, after approximately 30 seconds. At 1545 PAST, PGE reported to BPA overloads in the Rivergate area.

At 1545, BPA SCADA recorded the McNary 230-kV bus as receiving 347 MVAR from McNary and Hermiston was receiving six MVAR from the transmission system. Coyote Springs was taking seven MVAR from the McNary-Slatt 500-kV line. WNP Unit 2 was supplying 200 MVAR to the Ashe 500-kV bus. The John Day substation was receiving 408 MVAR from the John Day powerhouse. Big Eddy was receiving 77 MVAR total from The Dalles. The McNary generating units had boosted their reactive output from 260 MVAR to 475 MVAR (which was over their maximum sustained MVAR output for that power level) immediately following the Keeler-Allston trip.

At 1547:29, approximately five minutes after the 500-kV line trip, the PacifiCorp Merwin-St. Johns 115-kV line tripped due to a zone 1 KD relay malfunction. (The time stamp noted is from PAC's Portland Area Dispatch SCADA system. This system is not satellite synchronized, therefore, the exact time of the line trip and its place in the sequence of events are not known.) The line had been carrying 86 MW toward St.

Johns prior to the disturbance. Merwin and Yale generation was 82 MW, and Swift generation was 207 MW. There were 12 MW flowing from Cardwell to Merwin. The generation connected to this line did not trip and remained connected to the Longview area.

At 1547:36, the Ross-Lexington 230-kV line tripped after sagging too close to a tree and flashing over. This also forced the outage of PacifiCorp's generation at Swift (207 MW) connected to this line. The two Trojan 230-kV lines, now loaded to 150 percent of their emergency ratings, were the only west side ties between Portland and the 500-kV system to the north. There was also a 115-kV line from the north to Astoria, down the coast, that does connect back to the Willamette Valley.

The McNary units boosted their reactive output to 480 MVAR, then to 494 MVAR. They held this level for a short time, then began tripping. Two units tripped at 1547:40, followed by four more units four seconds later dropping the frequency to 59.9 Hz. At 1547:49, another unit tripped, followed eight seconds later by another unit, and another unit fifteen seconds after that. At 1548:47, two units tripped and, at 1549, the last two units tripped. The McNary unit trips the result of erroneous operations of a phase unbalance relay in the generator exciters. Relay replacement is in progress. Following the loss of the McNary units, the Boardman Plant was supplying 275 MVAR to Slatt in response to collapsing voltage while in constant excitation mode.

POWER OSCILLATIONS BEGIN

Following the generation loss at McNary, the power system began experiencing a mild oscillation. Grand Coulee, Chief Joseph and John Day began picking up the lost generation. When McNary generation had dropped to approximately 350 MW, the oscillation became negatively damped. Forty-five seconds after the Ross-Lexington line trip, the Malin 500-kV Shunt Capacitor Group 3 was automatically switched in. This raised the voltage, but the 0.224 Hz system oscillations continued to increase. Five seconds later, BPA's Eastern Control Center (ECC) SCADA operator switched in a 115-kV shunt capacitor group at Walla Walla. SCADA at BPA's Dittmer control center was receiving line load fluctuating alarms.

The PDCI also began to fluctuate in response to the AC voltage. The PDCI power controller maintains the power level by adjusting current without exceeding a 3,100 ampere DC line current limit. If the current reaches this limit, the power level necessarily reduces as the AC voltage declines. The PDCI response during the oscillation indicates that system inertia synchronizing power was reducing (decreasing DC power while the AC power was increasing). At 1548:51, when the AC system oscillations had increased to approximately 1,000 MW and 60 kV peak-to-peak at Malin, the voltage collapsed. At this point, the PDCI power level changed enough to initiate the DC Remedial Action Scheme (RAS) level 1 ten-second sliding window algorithm. This RAS action closed Shunt Capacitor Group 4 at Malin and inserted the Fort Rock series capacitors on all three 500-kV lines south of Grizzly. At the same time, the Buckley-Grizzly line opened at Buckley via zone 1 relay action.

Within the next two to three seconds, the ties between northern California and neighboring systems, and between Arizona/New Mexico/Nevada and Utah/Colorado opened due to out-of- step and low voltage conditions.

OBSERVATIONS/INTERTIE INSTABILITY

The loss of the Keeler-Allston 500-kV line at 1542:37 overloaded the 230-kV lines into the Portland area and led to the loss of the Ross-Lexington 230-kV line at 1548:36. Power shifting east of the Cascades led to additional reactive demands in the McNary area and consequent tripping of all thirteen units at McNary. Finally, growing oscillations reached a level that tripped all three lines of the COI in just over one minute.

Factors which may have contributed to the severity of the disturbance include:

- Reduced reactive margin at McNary and other power plants is not alarmed to the BPA dispatcher. Additionally, low side reactive power output is not available on control center monitors. Either of these items would have indicated a problem before loss of the Keeler-Allston line.

- Protective systems at McNary are designed to transfer regulator control from dynamic automatic mode to manual mode after boosting above the maximum excitation limit for a specific length of time. The unit is supposed to stay connected to the line after this operation but erroneous protective relay actions tripped the units off line.

- Other units in the McNary area were operating on constant power factor control rather than voltage control, preventing these units from providing needed reactive support (Coyote Springs and Hermiston Generation).

- Reactive power limits used on USCE generators are more restrictive than those used in planning and operating simulation studies.

- Some power system stabilizers (to damp system oscillations) were not operational at The Dalles (five units on line, three without PSS) and John Day (13 of 16 units on line, four without PSS) due to plant control problems.

- The present PDCI response to system swings at high current output and low AC source voltages.

- The Dalles generation was at a low level (300-400 MW, five of 22 units on line) due to spill requirements for fish migration.

- AGC systems responded to the loss of McNary generation by picking up most of the generation at plants farther north. This effectively increased the length of transmission circuits between Northwest generation and Southwest loads.

This disturbance has indicated the need to identify strategies that will protect against COI instability for the more severe, unforeseen events such as loss of transmission into the Portland area. It also highlights the need for continued vigilance to ensure that all equipment can be operated to its full rating or to the fullest extent possible and that planning and operational simulation studies correctly represent system limitations.

CALIFORNIA-OREGON INTERTIE SEPARATION

One-and-a-half cycles after the Buckley-Grizzly trip, the Malin voltage had reached 315 kV, and the Malin-Round Mountain No. 2 and No. 1 500-kV lines were tripped by the traveling wave relay switch-into-fault logic at 1548:52.632. (This underreaching-impedance type logic is supervised by a specified low voltage level that has been reached for a period of time and no traveling wave detection. These were the same relays that operated for the July 2 disturbance.) The loss of the two Malin-Round Mountain lines caused the AC RAS to initiate brake insertion and Low generator dropping. One cycle later, the AC RAS High generator dropping algorithm operated. Shortly after Malin-Round Mountain lines tripped, the John Day-Grizzly No. 1 500-kV line tripped at John Day, the Chief Joseph dynamic brake inserted, and the John Day-Grizzly No. 2 500-kV line tripped. Seventy milliseconds after the Malin-Round Mountain No. 2 line tripped, the Captain Jack-Meridian 500-kV line tripped. At the same time, voltage started to decay at the Vincent substation in southern California and units at Chief Joseph and Grand Coulee tripped via RAS action. Forty milliseconds later, the Grizzly-Malin No. 2 line opened at Grizzly, followed in 24 milliseconds by the Grizzly-Captain Jack 500-kV line opening at Grizzly. Less than 20 milliseconds after that, the Captain Jack-Olinda line opened at Captain Jack, completing separation of the California-Oregon Intertie (COI). The North island frequency rose to 60.9 Hz dropping to 60.4 Hz within two seconds where it remained for about fourteen minutes. The frequency crossed 60 Hz three minutes later.

PDCI RESPONSE

During the disturbance, the PDCI experienced several power reductions. Prior to the disturbance, the power order at Celilo was 2,848 MW north to south with all valve groups and converters in operation. There were three power dips during the disturbance. The first power dip was at 1548:52 caused by an AC voltage reduction at Celilo. The DC voltage dropped from 500 kV to 315 kV in response to the fluctuating AC voltage. After the COI separated, the AC voltage returned to normal and the DC power recovered.

The second power dip, at 1548:54, was caused by an AC voltage reduction at Sylmar resulting from the power swing following the opening of the COI. Sylmar reports AC voltages as low as 0.65 pu. The DC voltage dropped as low as 286 kV during this period. There were also commutation failures at Sylmar during this time. The voltage-dependent current limit switched on for a short period to ramp the current orders in both poles to 550 amps. The DC power level reached zero for a short period then recovered when the Sylmar AC voltage increased.

The third power dip on the DC occurred at 1548:58. It was also caused by AC voltage reduction at Sylmar. Sylmar Converters 1 and 2 blocked when the valve cooling systems tripped off due to the low AC voltage. Sylmar Valve Group 5 also blocked at this time, possibly due to loss of cooling flow in the test thyristor valve in that group. At 1549:01, Sylmar Valve Group 7 blocked. Celilo Valve Groups 5 and 7 and Converter 1 blocked in order to match the pole 3 operating voltage allowed by the remaining Sylmar operating configuration. Following this, the DC power level slowly recovered (as the Sylmar AC voltage recovered) to about 1,534 MW.

At 1605:12.4, Sylmar AC Filter Bank 4 relayed due to blown fuses probably caused by high harmonic current resulting from reduced voltage operation after the loss of the other valve groups. No action was taken to replace the lost reactive power from AC Filter Bank 4 because Sylmar's Reactive Power Controller had tripped off at 1548:54 due to low voltage. At this point the PDCI was drawing an estimated 1,000 MVAR from the 230-kV AC system at Sylmar. The LDWP senior load dispatcher, concerned about the excessive reactive power draw and the sequential uncontrolled loss of equipment over the previous ten minutes, ordered the PDCI to be manually ramped down and blocked. The PDCI ramp began at 1606:19 and the PDCI was blocked at 1612.

NORTHERN ISLAND DETAILS

This island consisted of Oregon, Washington, Idaho, Montana, Wyoming, British Columbia, Utah, Colorado, Western South Dakota, Western Nebraska, and Northern Nevada. This island was formed following the separation of the COI and out-of-step tripping on the Northeast/Southeast boundary.

Shortly after the Captain Jack-Olinda line opened, the Malin south bus differentials operated to deenergize the PAC 500/230-kV transformer. The Grizzly-Summer Lake line (and Ponderosa tap) relayed. All remaining lines on the Oregon section of the COI were tripped between John Day and Malin. The loss of the 230-kV connection at Malin subsequently led to the loss of the BPA Malin-Warner 230-kV line as well as PAC connections between Meridian and Redmond. The Lapine-Chiloquin 230-kV, Lapine-Fort Rock 115-kV, Lapine-Midstate Electric 115-kV, Pilot Butte-Lapine 230-kV, Redmond-PacifiCorp 115-kV (Prineville) and 230-kV (Pilot Butte) circuits tripped at 1550.

At 1548, three Columbia Aluminum Company feeders at Harvalum tripped by undervoltage relay within the plant, and 279 MW of load was lost. Also at 1548, three Northwest Aluminum Company feeders were tripped at Harvey, again by undervoltage relay within the plant, interrupting 154 MW of load. All six feeders were restored at 1633.

PAC lost about 450 MW of load, interrupting service to 154,000 customers in portions of southern and central Oregon, and northern California. Power was restored between 1620 and 1701.

MPC Colstrip Units 3 and 4 (750 MW each) tripped by ATR at 1548:53.622; Unit 1 (320 MW) tripped 27 ms later (also by ATR). IPC's CJ Strike Unit 3 (29 MW) tripped at 1549 due to exciter problems. Strike was restored at 1614. Colstrip Units 1 and 3 were restored at 1656 and 1707. Unit 4 was restored at 04:29 on August 11.

In BCHA's area, three Independent Power Producer (IPP) units were tripped on overfrequency at 1549. They were McMann Units 1 and 2 (90 MW) and NWE Unit 1 (70 MW). At approximately the same time, a 500-kV cable circuit between the Malaspina and Dunsmuir substations tripped on overvoltage (trip setting of 571.5 kV with a 250-millisecond delay).

BPA's SVC at Keeler tripped at 1548:58.251 when the cooling system tripped on undervoltage. The SVC controller was reset at 1549. The section lockout relays were reset at 1823 and disconnects closed at 1835. The Keeler SVC was back in service at 1945.

About one-and-a-half seconds after COI separation, the BCHA and MPC interconnections with BPA began large oscillations due to the NE/SE out-of-step separation.

The BCHA-BPA tie flows ramped from 2,300 MW to zero (export small amount to Canada) two minutes after the disturbance. At 1554, a 100-MW flow increase into BCHA was observed. After 1554, BCHA began exporting about 1,000 MW to the Northwest, following the loss of the BCHA-Alberta tie which was carrying 1,230 MW into Alberta at the time. The frequency stayed high in the Northern Island (about 60.4 Hz for 14 minutes, crossing 60 Hz after 17 minutes, dipping as low as 59.95 Hz, then rising to 60.04 Hz for the next 50 minutes). Despite having no direct schedules to California, BCHA cut schedules by 600 MW to reduce island frequency.

At 1628:50, the frequency dipped from 60 Hz to 59.9 momentarily, overshooting to 60.04 then recovering to 60 Hz.

NORTHERN ISLAND RESTORATION

The 230-kV Ross-Lexington line was restored at 1626; the Keeler-Allston 500-kV line was restored at 2057; the John Day-Marion and Marion-Lane 500-kV lines at 2250. The Big Eddy-Ostrander 500-kV line remained out of service overnight.

The Chief Joseph 230-kV powerhouse lines that were tripped by RAS action were energized at 1557.

McNary powerhouse was back on line in twenty minutes.

Restoration on the Oregon portion of the COI began at 1552 and was completed at 1657. The Grizzly terminal of the Round Butte line was opened at 1550. The John Day-Grizzly line and Grizzly north bus were returned to service at 1553. The Grizzly-Captain Jack line was energized briefly but was opened again due to high bus voltage. Many shunt reactors were then switched around the system to alleviate the high voltages. The John Day-Grizzly No. 2 line and the Grizzly south bus were returned to service at 1607. The Grizzly-Malin No. 2 line was closed at 1608, energizing the Malin north bus. The Malin-Captain Jack No. 1 line and Captain Jack south bus were returned to service at 1611. The Malin No. 2 reactor would not stay closed and cycled at various times until the SCADA operator locked it out at 1632. At 1617, the Grizzly-Summer Lake line was energized and the line reactor placed in service. At 1628, the Captain Jack PCB 4986 was closed, energizing the PAC Meridian line. At 1643, the Summer Lake PCB 4958 was closed, energizing the PAC line to Midpoint, and immediately thereafter, the Midpoint PCB 544A was closed, returning the line to service. At 1648, the Malin PCB 4019 was closed, energizing the PAC 500/230-kV transformer, but it tripped free on phase discordance. At 1651, Malin energized to Summer Lake through PCB 4576. The PAC Summer Lake-Malin 500-kV line was returned to service by closing PCB 4576 at Malin and PCB 4957 at Summer Lake, at 1651 and 1652 respectively. At 1653, Malin PCB 4019 was closed by the local operator, energizing the PAC 500/230-kV transformer at Malin. At 1657, the Grizzly-Captain Jack 500-kV line was returned to service. This placed two lines in service from John Day to Grizzly and three lines from Grizzly to Malin and Captain Jack, ready to close to Round Mountain and Olinda.

At 1701, there were two complete bays at Grizzly. At 1702, the Captain Jack north bus was hot and two bays completely restored. At 1703, the ring bus at Summer Lake was closed up. At 1704, the Buckley-Grizzly 500-kV line was in service. At 1708, a third bay was complete at Grizzly. At 1707, the John Day bays were completely restored. At 1707, the first complete bay was restored at Malin. At 1712, Grizzly PCB 5040 was closed to Round Butte. At 1749, the Fort Rock series capacitors were bypassed.

At 1813, Captain Jack PCB 4980 was closed, energizing the line to Olinda. The closure of the Captain Jack-Olinda 500-kV line at 1818 completed the first tie to the Northern California Island. At 1829, Malin PCB 4064 was closed, energizing the Round Mountain No. 1 line. The remaining circuit breaker to complete the bay was closed at 1830. The Malin-Round Mountain No. 2 line remained out of service until 0708 on August 11 for insulator repairs. The last Captain Jack bay was restored at 1836.

The PDCI was restored to operation in 010 + 010 configuration at 1747, continuing through stages to full configuration of 311+311 at 1831.

BPA and PAC 115-kV and 230-kV circuits in Central Oregon were restored at 1628. PAC load in southern and central Oregon and northern California was restored by 1701.

In the following islands, restoration of customer service was impeded due to the large amount of thermal generation that tripped off line during the disturbance and the fact that it took almost an hour to restore system frequency to 60 Hz.

NORTHERN CALIFORNIA ISLAND DETAILS

This island was formed following out-of-step conditions and low voltages between Midway and Vincent two seconds after COI separation and following separation from Sierra Pacific at 1548.

At 1548:54.7 PAST, the Midway-Vincent No. 1 and No. 2 500-kV lines opened. Just prior to this action, the 500-kV bus voltage at Vincent was at 40 percent of normal. The Midway-Vincent No. 3 500-kV line tripped 65 milliseconds later. Line 2 tripped via channel C phase comparison relay, line 1 tripped via channel C out-of-step relay, and line 3 tripped via channel M out-of-step relay. Voltage was collapsing at about 7.5 kV/cycle just prior to these trips. These trips separated northern California from southern California.

During this same time frame, the Drum-Summit No. 1 and No. 2 115-kV lines tripped, separating PG&E from SPP.

The Olinda 500/230-kV transformer tripped on over voltage at 1549:47.366. The Tracy 500/230-kV transformer tripped by over voltage relay at 1549:51.899.

Frequency within the Northern California Island dropped to 58.3 Hz eight minutes into the disturbance. The underfrequency load shedding program within this island tripped all 10 blocks of load, representing approximately 50 percent of the northern California load. Numerous generating units tripped, including Diablo Canyon Units 1 and 2 (2,164 MW) at 1548.55.141 and 1548.55.405; Moss Landing Units 6 and 7 (1,474 MW) at 1551:47.420 and 1552:17.536; Morro Bay Units 1, 2, 3, and 4 (749 MW) at 1550; Contra Costa Units 6 and 7 (670 MW) at 1556; Hunters Point Unit 2 (10 MW) at 1550; Pit No. 1 Powerhouse Unit 1 at 1547, and Pit No. 7 Powerhouse Unit 7 (13 MW) at 1552. CDWR generation totaling 929 MW was lost at 1550, 1555 and 1557 due to the Table Mountain-Thermalito 230-kV 1, 2, and 3 lines relaying. The most likely cause was the No. 2-230 kV line sagging into a pine tree, flashing over and causing a fire. The fire spread to cause flashovers on the No. 1 and 3-230 kV lines. The Diablo Canyon units were tripped due to loss of synchronism, by directional instantaneous overcurrent relays looking into the unit step-up transformers. The units appeared to be stable with the remaining system until the Midway-Vincent lines relayed. Moss Landing Unit 7, Morro Bay Unit 1, and Contra Costa Units 6 and 7 relayed by loss of field. Moss Landing Unit 6 relayed due to volts/hertz overexcitation and regulator voltage balance. Morro Bay Unit 3 relayed due to undervoltage and Morro Bay Unit 4 by underfrequency. High voltage occurred on the 500-kV and 230-kV system; the North and South ties opened; and load was tripped. This high voltage, along with low frequency, contributed to the tripping of units. Volts/hertz relays primarily at Moss Landing and Contra Costa overrode other excitation protection and played a major role tripping the units.

In all, the Northern California Island lost 7,937 MW of generation and 11,602 MW of load (representing approximately 2.9 million customers) during the disturbance.

In addition to automatic load shedding in the island, the Fresno area manually reduced 80 MW of load to help recover system frequency at 1554. At 1556:03, the PG&E frequency dropped to 58.3 Hz due to the loss of generation in the island. The last two blocks (blocks 9 and 10) of underfrequency load were shed. An automatic protection scheme at Martin Substation operated to separate San Francisco from the Northern California Island when frequency declined to 58.3 Hz.

After the initial swing, when the frequency dropped to 58.5 Hz, frequency rapidly overshot to 60.7 Hz and fluctuated slightly above 60 Hz for over three minutes. Some of PG&E's load began automatically restoring after three minutes. (The PG&E load shedding program is designed to restore load in three to six minutes after frequency returns to near 60 Hz.) Over the next five minutes, as load was automatically restored and additional generation was tripped, frequency further declined to 58.3 Hz so that the load that had been automatically restored was tripped again. Frequency then returned to slightly above 59.0 Hz, where it began to stabilize. By 1600, 4,320 MW of load had been restored on the PG&E system. At 1607, frequency returned to 59.5 Hz where it stayed for approximately 75 minutes. At 1722, PG&E dispatchers manually shed load to bring the frequency back to normal. The low frequency in the Northern California Island prevented a parallel from being made with the Northern Island. From 1722 to 1732, PG&E manually shed 2,524 MW of load in Blocks 9 and 10. These blocks were restored by 2037.

Pit units were restored at 1641 and 1651. Hunters Point No. 2 was paralleled with the system at 1755.

At 1818, the COI was reestablished when the Captain Jack-Olinda line was closed. The Malin-Round Mountain No. 1 line was restored at 1829. The Malin-Round Mountain No. 2 line remained out of service because of damaged insulators. At 1843, Contra Costa Unit 6 was synchronized to the system.

Connections to southern California were restored at 1847 when the Midway-Vincent No. 1 and No. 3 lines were restored. The Midway-Vincent No. 2 line was closed at 1848.

The 115-kV ties to Sierra Pacific were restored at 1915. Morro Bay Unit 2 was paralleled at 2000.

By 2154, 91 percent of the PG&E customers were restored with all customers restored by 0100 on August 11. Morro Bay Units 1 and 3 were paralleled, respectively, at 2301 and 2318.

Moss Landing Unit 6 paralleled at 04:11 on August 11, while Unit 7 was paralleled at 1800 on August 11. Diablo Canyon Unit 2 was returned to service at 1431 on August 15, Unit 1 at 0410 on August 16.

Underfrequency detection on UPS at Western's control center in Folsom switched communication, computer and SCADA equipment from the AC power feed to DC power (batteries). At 1614, the UPS failed because of low battery voltage interrupting power to the communication, computer and SCADA equipment. The emergency generator was not designed to startup on underfrequency and it didn't switch on undervoltage due to high AC voltage in the island. Losing their SCADA at 1614 prevented Western from switching out 800 MVAR of 500 kV shunt capacitors at Olinda and Tracy, exacerbating high voltage in the island. At 1655, equipment was bypassed to restore AC power to critical equipment and at 1715, the UPS was restored.

SMUD lost 1,000 MW and 160,586 customers during the disturbance. Most of the load was automatically shed by underfrequency relay, but 384 MW was manually shed. Load restoration was completed at 2103.

SOUTHERN ISLAND DETAILS

This island consisted of southern California, Arizona, New Mexico, southern Nevada, Northern Baja California, and El Paso, Texas. This island was formed due to out-of-step conditions and low voltage between Midway and Vincent and out-of-step conditions on the Northeast/Southeast boundary. Generation totaling 13,497 MW was tripped, along with 15,820 MW of load (4.2 million customers).

By 1548:54.938, separation of the NE/SE boundary (TOT2) including the Hesperus-Waterflow 345-kV, Lost Canyon-Shiprock 230-kV, Glen Canyon-Sigurd 230-kV, Glade Tap-Durango 115-kV, Red Butte-Harry Allen 345-kV, and Pinto-Four Corners 345-kV lines, was complete, with all lines tripping due to out-of-step conditions. Frequency in this island dropped to approximately 58.5 Hz, triggering underfrequency load shedding. In this island, key generating units tripped, including Palo Verde No. 1 and No. 3 (2,493 MW), all three Navajo units 2,130 MW), Mohave Unit 2 (642 MW), Four Corners Unit 5 (762 MW), Cholla Unit 1 (107 MW), Coronado Unit 2 (357 MW), all Glen Canyon units (700 MW), Ormond Beach Unit 2 (689 MW), Encina Units 4 and 5 (323 MW), South Bay Unit 1 (92 MW), Etiwanda (318 MW) and 200 MW of Phoenix area generation.

At 1549, Intermountain Unit 1 (854 MW) tripped due to a sub-synchronous resonance protective relay operation (the SSR relay operated in response to commutation failures, not SSR). The Intermountain-Adelanto HVDC southern Transmission System (STS) ramped down by the appropriate amount in response to the unit trip. Several minutes later, Intermountain Unit 2 ramped down by approximately 200 MW due to boiler instability. Again the STS ramped down by the appropriate amount in response.

Units at Scattergood (at 1555) and Haynes (at 1549) in the LDWP control area were also tripped as well as many other smaller units at numerous locations across the Southern Island.

The three Navajo units tripped when a potential transformer on a series capacitor failed. The resulting fire and smoke caused a phase-to-phase fault on the Navajo-McCullough 500-kV line. Four seconds before this, the Navajo-Moenkopi line had tripped on out-of-step. Loss of these two lines left only the Navajo-Westwing line to carry power from the three Navajo units and it tripped on out-of-step, leaving the units isolated.

At 1549, the 345-kV Pinnacle Peak terminal of the Glen Canyon-Flagstaff-Pinnacle Peak 1 and 2 lines opened, initiating the RAS to trip four units at Glen Canyon, leaving three units generating 300 MW. The 345-kV voltage at Glen Canyon was 506 kV, tripping the east bus. Ten minutes later, the WAUC dispatch center at Montrose was ready to parallel at Flagstaff but the WALC dispatch center in Phoenix was unable to close the Pinnacle Peak 345/230-kV transformer breakers because the relay was still detecting an overexcitation condition. An operator had to be called out.

At 1617, the 230-kV Glen Canyon-Navajo, Kayenta-Navajo and Kayenta-Shiprock lines relayed, islanding the three units at Glen Canyon.

At 1621, the Glen Canyon-Navajo-Kayenta line was energized, but a phase shifter differential operation at Glen Canyon sent a transfer trip signal to Navajo.

At 1632, Glen Canyon unit 4 was put on line to provide station service. At 1633, the west bus relayed on overvoltage. Unit 6 was placed on-line at 1633. At 1640, the Glen Canyon-Navajo line was energized and the Glen Canyon east bus was energized one minute later. At 1644, the Flagstaff terminals of the Glen Canyon and Pinnacle Peak lines were opened in preparation for a return to service.

At 1750, the 345-kV Glen Canyon-Flagstaff No. 2 line was energized to Flagstaff and the Flagstaff bus was energized two minutes later. One minute later, the Glen Canyon-Flagstaff No. 1 line was in service, as well as the Flagstaff-Pinnacle Peak No. 1 345-kV line. The Flagstaff-Pinnacle Peak No. 2 line was in service at 1756.

All Glen Canyon units were returned to service by 1752.

At 1606:47, an additional 1,400 MW of manual load shedding was implemented by SCE at Valley 115-kV, Villa Park 66-kV and Chino 66-kV substations to help restore system frequency.

The frequency in the Southern Island remained below 60 Hz for over an hour. SRP manually shed 216 MW of load (after tripping 1,444 MW by underfrequency relaying).

As the frequency in the Southern Island began to recover and several key units in the Southern Island returned to service, system load restoration began at 1657. The frequency returned to normal at 1655 PAST.

At 1847, twenty-nine minutes after the Northern California Island synchronized to the Northern Island, Midway-Vincent 500-kV lines No. 1 and No. 3 were paralleled at Vincent, reestablishing the 500-kV tie between PG&E and SCE and reconnecting the Southern and Northern California Islands. At 1848, Midway-Vincent No. 2 was returned to service. Between 1850 and 1857, starting with the Four Corners-Pinto

345-kV line, the NE/SE lines were returned to service, completely restoring the WSCC bulk power transmission system.

By 2142, all the load shed in the Southern Island during the disturbance had been restored.

Major unit restoration began with Coronado Unit 2 at 1730, followed by Ormond Beach Unit 2 at 1915, Springerville Unit 1 at 2131, and Navajo Unit 1 at 2215. Palo Verde Unit 3 returned to service on August 11 at 1756 and Unit 1 was synchronized at 0454 on August 12. Navajo Unit 3 was the last of the major units to be restored, returning to service at 0608 on August 12.

ALBERTA ISLAND DETAILS

At 1554, approximately five minutes after the Northern Island separated from the rest of WSCC, the BCHA to Alberta interconnection (138-kV and 500-kV) tripped, separating the Alberta system from the Northern Island. At the time of the separation, the interconnection was supplying 1,230 MW to Alberta. The 138-kV tie tripped on transformer overcurrent and the parallel 500-kV tie tripped on undervoltage. Governor action in response to high frequency caused the loading on this interconnection to increase from 400 MW to 1,230 MW prior to the lines tripping. Frequency in the Alberta Island dipped to 59.0 Hz. In this island, 146 MW of generation was tripped and 968 MW of load was lost by underfrequency load shedding, affecting 192,000 customers. Alberta resynchronized with British Columbia at 1629. All load was restored by 1739.

Detailed data for each system are included in Appendices 1 through 4.

V. SEQUENCE OF EVENTS

See Appendix 5

VI. DISTURBANCE EVALUATION CHECKLIST

DISTURBANCE CATEGORY	DEFINITION	CONTRIBUTING FACTOR IN CAUSING THE DISTURBANCE, INCREASING ITS SEVERITY, OR HINDERING RESTORATION? (YES OR NO)	EXPLANATORY COMMENTS
1. Power System Facilities	The existence of sufficient physical facilities to provide a reliable bulk power supply system.	No	
2. Relaying Systems	Detection of bulk power supply parameters that are outside normal operating limits and activation of protection devices to prevent or limit damage to the system.	Yes	There were erroneous relay actions on exciters at McNary and the Merwin-St. Johns 115-kV line. The McNary units tripped at high reactive output levels.
3. System Monitoring, Operating, Control, and Communications Facilities	Ability of dispatch and control facilities to monitor and control operation of the bulk power supply system. Adequacy of communication facilities to provide information within and between control areas.	Yes	Several EMS/SCADA systems failed for a variety of reasons during the disturbance.
4. Operating Personnel Performance	Ability of system personnel to react properly to unanticipated circumstances which require prompt and decisive action.	Yes	One 500-kV line outage was known to PGE and another to PG&E by interutility data exchange, but the three 500-kV line outages experienced by BPA during the hour and a half prior to the disturbance were not reported to other WSCC members. NWPP procedures in place at the time did not identify the lines as "key" facilities for notification purposes. BPA operators did not understand the implications of a potential Keeler-Allston 500-kV line outage and take the necessary steps to mitigate its impact on system operation.
5. Operational Planning	Study of near term (daily, weekly, seasonal) operating conditions. Application of results to system operation.	Yes	BPA failed to identify the Keeler-Allston 500-kV line outage as a critical outage and develop a contingency plan. Reduced support from Lower Columbia plants was not accounted for in operating studies.
6. System Reserve and Generation Response	Ability of generation or load management equipment to maintain or restore system frequency and tie line flows to acceptable levels following system disturbance.	Yes	Governor action in Alberta overloaded and tripped BCHA/TAUC ties. There was uncontrolled loss of generation in the underfrequency islands.

DISTURBANCE CATEGORY	DEFINITION	CONTRIBUTING FACTOR IN CAUSING THE DISTURBANCE, INCREASING ITS SEVERITY, OR HINDERING RESTORATION? (YES OR NO)	EXPLANATORY COMMENTS
7. Preventive Maintenance	A program of routine inspections and tests to detect and correct potential equipment failures.	Yes	Inadequate right-of-way maintenance (tree trimming) was a significant factor in this disturbance. Previously identified danger trees had not been trimmed or removed.
8. Load Relief	The intentional disconnection of customer load in a planned and systematic manner to restore the balance between available power supply and demand.	Yes	Coordination of underfrequency load shedding was inadequate.
9. Restoration	Orderly and effective procedures to quickly reestablish customer service and return the bulk power supply system to a reliable condition.	Yes	Automatic load restoration delayed frequency recovery in the Northern California Island. Southern Island manual load restoration was not effectively coordinated. Cutting complex schedules is difficult and time consuming, delaying frequency recovery.
10. Special Protection Systems	Use of relays to initiate controlled separation and generator tripping to prevent a widespread blackout.	Yes	The NE/SE Separation Scheme was not in service. That may have caused additional transmission and unit tripping.
11. System Planning	Comprehensive planning work utilizing appropriate planning criteria to provide a reliable bulk power supply system.	Yes	Generator reactive capabilities used in planning studies were higher than the actual capabilities for key units along the lower portion of the Columbia River. PSS was represented in studies at unrealistically high in-service levels.
12. Other	Any other factor not listed above which was significant in causing the disturbance, making the disturbance more severe or adversely affecting restoration.	Yes	Generator underfrequency protection is not adequately coordinated with other UF programs.

VII. EXHIBITS

Summary of Plots and Figures: Very good information was obtained from the Portable Power System Monitor (PPSM) at Dittmer and other locations on the power system to help reconstruct the events of the disturbance. A selection of plots is provided showing some of the key events described. PPSM scaling may be in error on some plots. Subtract 5 seconds from time scale to match sequence of events timing.

Exhibit 1 Response to loss of Keeler-Allston (Dittmer PPSM)
Shown in **Exhibit 1A** are step changes in line flows in the northwest resulting from outage of the Keeler-Allston line. **Exhibit 1B** includes voltage at Slatt (near McNary) showing reduction in voltage. Also shown is response on COI as indicated by PG&E Olinda MW. Oscillation is lightly damped.

Exhibit 2 Response to loss of Ross-Lexington (Dittmer PPSM)
Exhibits 2A-2F show the Northwest response on selected lines and generators to the Ross-Lexington trip. **Exhibit 2D** illustrates the reduction in power at McNary resulting from sequential tripping of all 13 units. All figures show the system oscillation of 0.224 Hz which began at the time of loss of Ross-Lexington and initial tripping of McNary units and becomes more negatively damped (unstable) as additional units are tripped. **Exhibit 2A** shows that voltage at Malin drops lower on successive swings until the COI opens. **Exhibit 2F** shows a detailed plot of the initial response following loss of the Ross-Lexington line before the system oscillation began to grow.

Exhibit 3 DC Schedule-Actual (Dittmer PPSM)
This figure shows the response of the PDCI at the time of COI separation. Dynamic swings on the PDCI resulted in initiating PDCI remedial actions. Also initiated is the PDCI algorithm to automatically change schedules to actuals intended to minimize impact of a monopole outage on the COI initiated by swings on the PDCI.

Exhibit 4 COI and Midway-Vincent Separations (PG&E DSM)
Shown are the responses for the North Tie (Malin-Round Mountain 1 and 2) and the South Tie (Midway-Vincent). Outage of the South Tie occurs very soon after loss of the North Tie (approximately 2 seconds) as a power reversal occurs to support the northern California area.

Exhibit 5 Table Mountain response at time of separation (PG&E DSM) **Exhibit 5A** shows Table Mountain voltage and frequency. **Exhibit 5B** shows MW and MVAR flows at Table Mountain. **Exhibit 5C** shows a detailed plot of the system oscillation.

Exhibit 6 - McNary MVAR (USCE McNary recorder)
This Exhibit shows the initial plant loading of 260 MVAR followed by an increase to over 360 MVAR after loss of the Keeler-Allston and Ross-Lexington lines.

Exhibit 7 - SCE Island frequency (SCE recording)
This figure shows the frequency decline in the Southern Island following the disturbance.

Exhibit 8 - Diagram with northwest sequence of events.

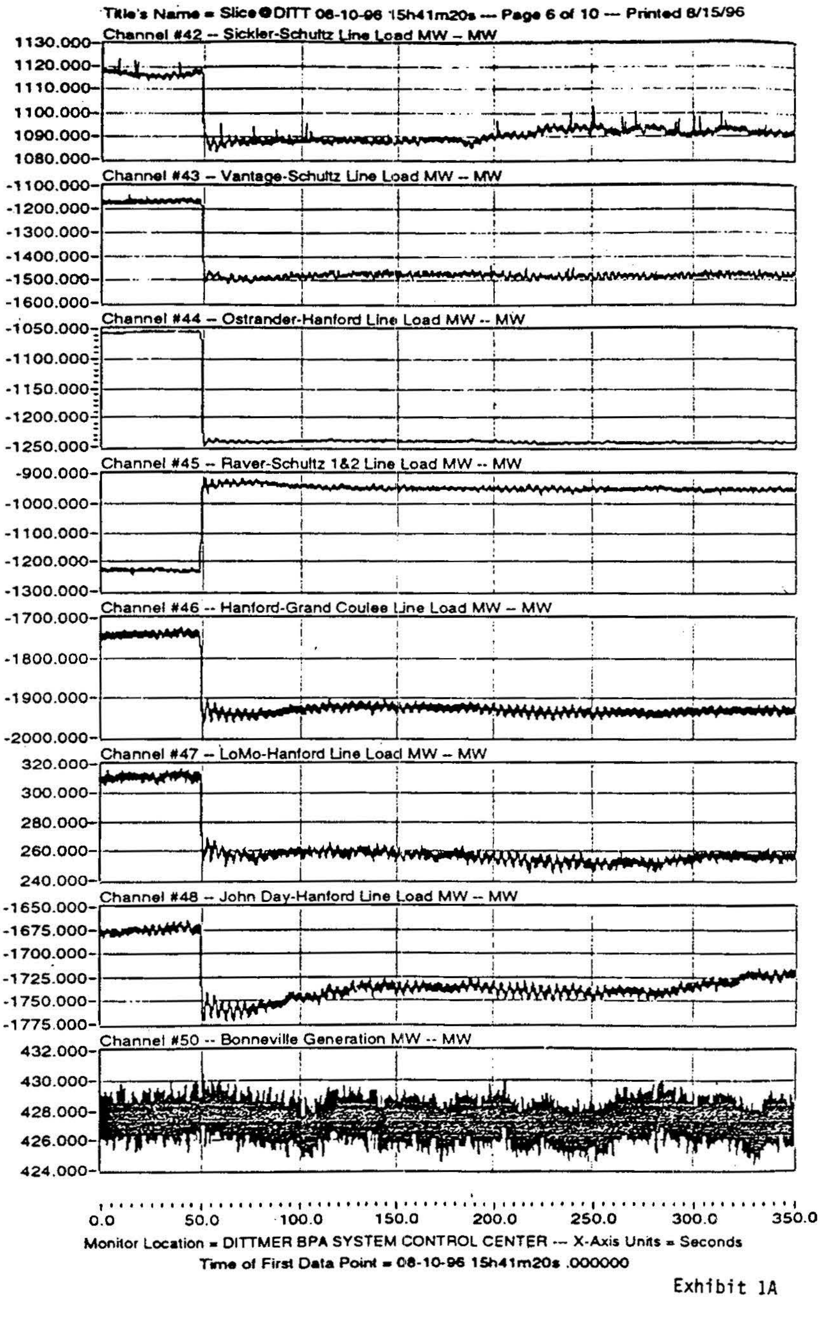
Exhibit 9 - Map showing islands formed and sequence of significant events leading to separation.

Exhibit 10 - BCHA-Alberta power transfer, frequency plots for Alberta, and BPA frequency/time error plots.

Exhibit 11 - PG&E frequency plot, indicating unit tripping and load shedding times.

Exhibit 12 - WSCC Interchange Diagram and Supplemental Line Flow Report; Hour Before Disturbance

36-069 - 97 - 5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Channel #42 -- Sickler-Schultz Line Load MW -- MW
1130.000
1120.000
1110.000
1100.000
1090.000
1080.000
Channel #43 -- Vantage-Schultz Line Load MW -- MW
-1100.000
-1200.000
-1300.000
-1400.000
-1500.000
-1600.000
Channel #44 -- Ostrander-Hanford Line Load MW -- MW
-1050.000
-1100.000
-1150.000
-1200.000
-1250.000
Channel #45 -- Raver-Schultz 1&2 Line Load MW -- MW
-900.000
-1000.000
-1100.000
-1200.000
-1300.000
Channel #46 -- Hanford-Grand Coulee Line Load MW -- MW
-1700.000
-1800.000
-1900.000
-2000.000
Channel #47 -- LoMo-Hanford Line Load MW -- MW
320.000
300.000
280.000
260.000
240.000
Channel #48 -- John Day-Hanford Line Load MW -- MW
-1650.000
-1675.000
-1700.000
-1725.000
-1750.000
-1775.000
Channel #50 -- Bonneville Generation MW -- MW
432.000
430.000
428.000
426.000
424.000
0.0
50.0
100.0
150.0
200.0
250.0
300.0
350.0
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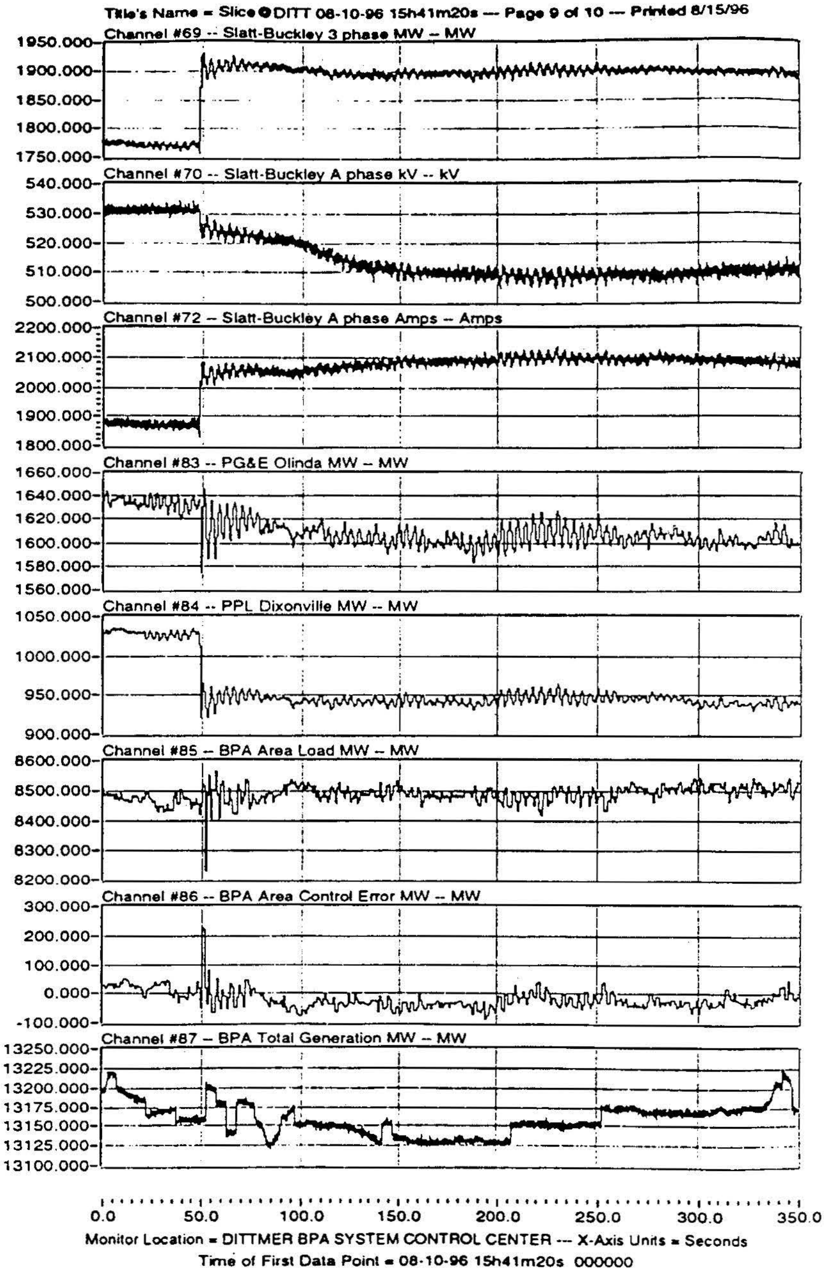
Exhibit 1A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Channel #69 -- Slatt-Buckley 3 phase MW -- MW
1950.000
1900.000
1850.000
1800.000
1750.000
Channel #70 -- Slatt-Buckley A phase kV -- kV
540.000
530.000
520.000
510.000
500.000
Channel #72 -- Slatt-Buckley A phase Amps -- Amps
2200.000
2100.000
2000.000
1900.000
1800.000
Channel #83 -- PG&E Olinda MW -- MW
1660.000
1640.000
1620.000
1600.000
1580.000
1560.000
Channel #84 -- PPL Dixonville MW -- MW
1050.000
1000.000
950.000
900.000
Channel #85 -- BPA Area Load MW -- MW
8600.000
8500.000
8400.000
8300.000
8200.000
Channel #86 -- BPA Area Control Error MW -- MW
300.000
200.000
100.000
0.000
-100.000
Channel #87 -- BPA Total Generation MW -- MW
13250.000
13225.000
13200.000
13175.000
13150.000
13125.000
13100.000
0.0
50.0
100.0
150.0
200.0
250.0
300.0
350.0
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Time of First Data Point = 08-10-96 15h41m20s 000000

Exhibit 1B

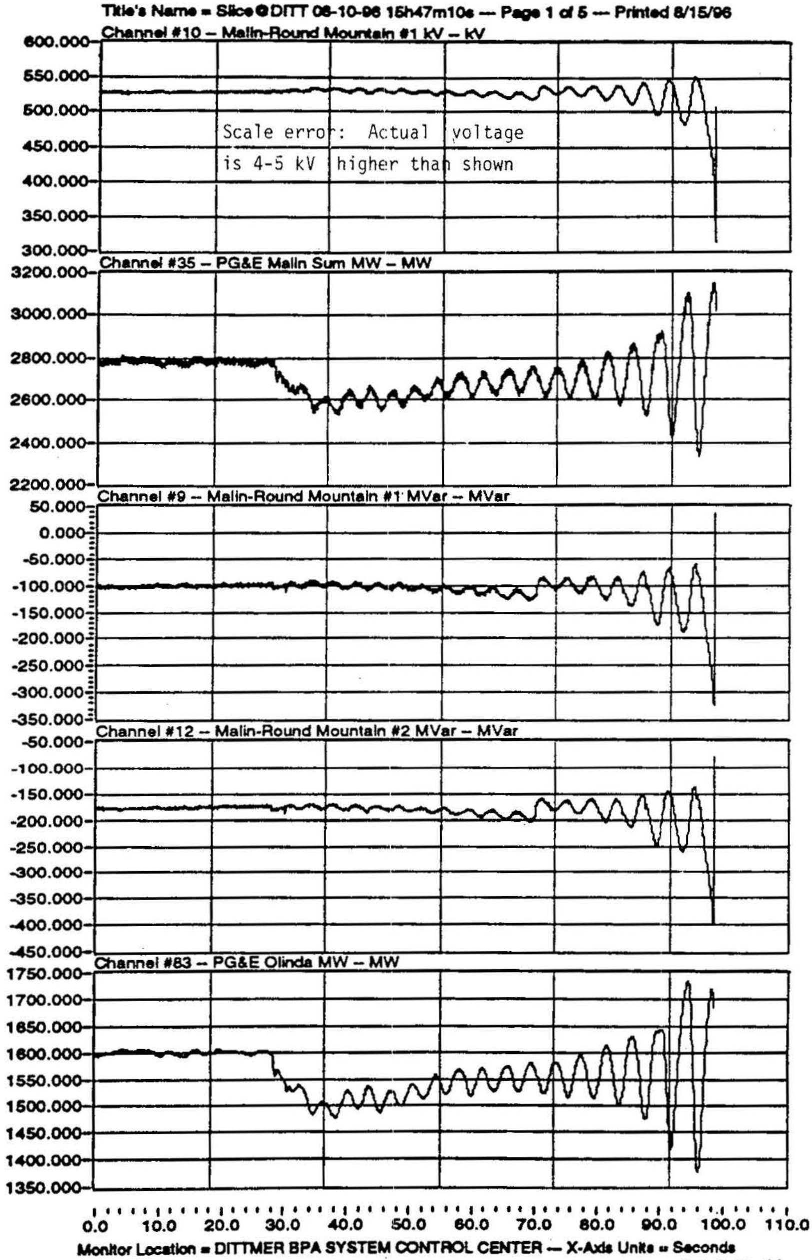
Title's Name = Slice@DITT 08-10-96 15h47m10s — Page 1 of 5 — Printed 8/15/96
Channel #10 – Malin-Round Mountain #1 kV – kV
600.000
550.000
500.000
450.000
400.000
350.000
300.000
Scale error: Actual voltage
is 4-5 kV higher than shown
Channel #35 – PG&E Malin Sum MW – MW
3200.000
3000.000
2800.000
2600.000
2400.000
2200.000
Channel #9 – Malin-Round Mountain #1 MVar – MVar
50.000
0.000
-50.000
-100.000
-150.000
-200.000
-250.000
-300.000
-350.000
Channel #12 – Malin-Round Mountain #2 MVar – MVar
-50.000
-100.000
-150.000
-200.000
-250.000
-300.000
-350.000
-400.000
-450.000
Channel #83 – PG&E Olinda MW – MW
1750.000
1700.000
1650.000
1600.000
1550.000
1500.000
1450.000
1400.000
1350.000
0.0
10.0
20.0
30.0
40.0
50.0
60.0
70.0
80.0
90.0
100.0
110.0
Monitor Location = DITTMER BPA SYSTEM CONTROL CENTER — X-Axis Units = Seconds
Time of First Data Point = 08-10-96 15h47m05s.000000

Exhibit 2A

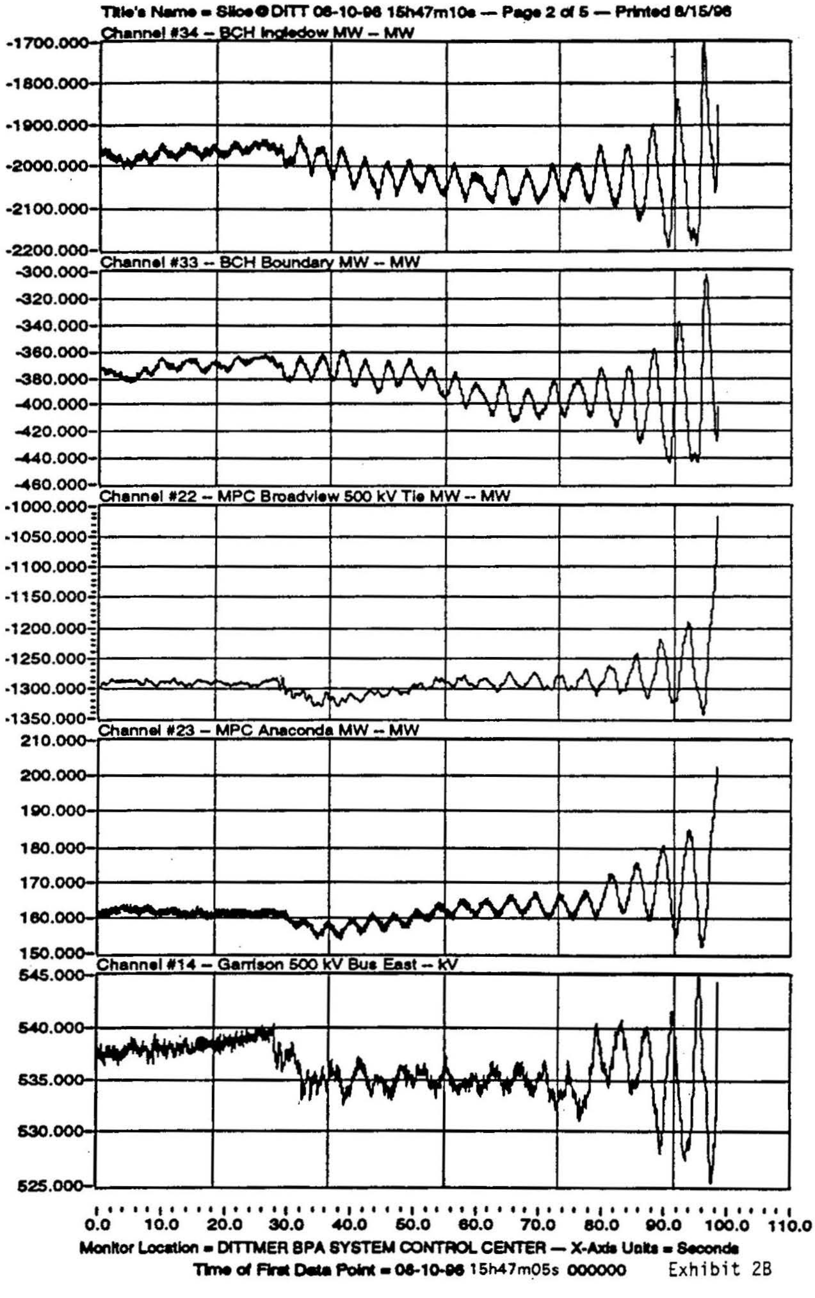
Title's Name = Slice@DITT 08-10-96 15h47m10s — Page 2 of 5 — Printed 8/15/96
Channel #34 — BCH Ingledow MW — MW
-1700.000
-1800.000
-1900.000
-2000.000
-2100.000
-2200.000
Channel #33 — BCH Boundary MW — MW
-300.000
-320.000
-340.000
-360.000
-380.000
-400.000
-420.000
-440.000
-460.000
Channel #22 — MPC Broadview 500 kV Tie MW — MW
-1000.000
-1050.000
-1100.000
-1150.000
-1200.000
-1250.000
-1300.000
-1350.000
Channel #23 — MPC Anaconda MW — MW
210.000
200.000
190.000
180.000
170.000
160.000
150.000
Channel #14 — Garrison 500 kV Bus East — kV
545.000
540.000
535.000
530.000
525.000
0.0 10.0 20.0 30.0 40.0 50.0 60.0 70.0 80.0 90.0 100.0 110.0
Monitor Location = DITTMER BPA SYSTEM CONTROL CENTER — X-Axis Units = Seconds
Time of First Data Point = 08-10-96 15h47m05s 000000

Exhibit 2B

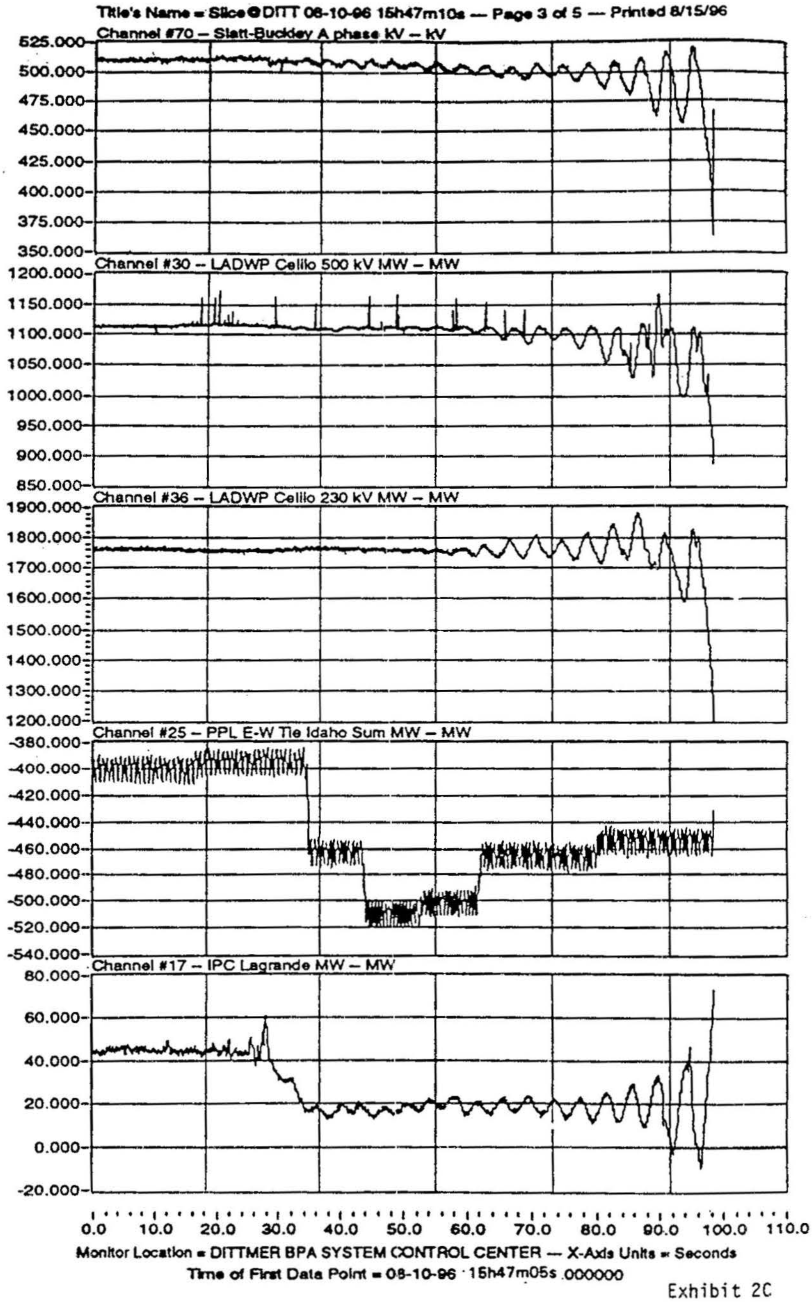
Title's Name = Slice@DITT 08-10-96 15h47m10s — Page 3 of 5 — Printed 8/15/96
Channel #70 – Slatt-Buckley A phase kV – kV
Channel #30 – LADWP Celilo 500 kV MW – MW
Channel #36 – LADWP Celilo 230 kV MW – MW
Channel #25 – PPL E-W Tie Idaho Sum MW – MW
Channel #17 – IPC Lagrande MW – MW
0.0 10.0 20.0 30.0 40.0 50.0 60.0 70.0 80.0 90.0 100.0 110.0
Monitor Location = DITTMER BPA SYSTEM CONTROL CENTER — X-Axis Units = Seconds
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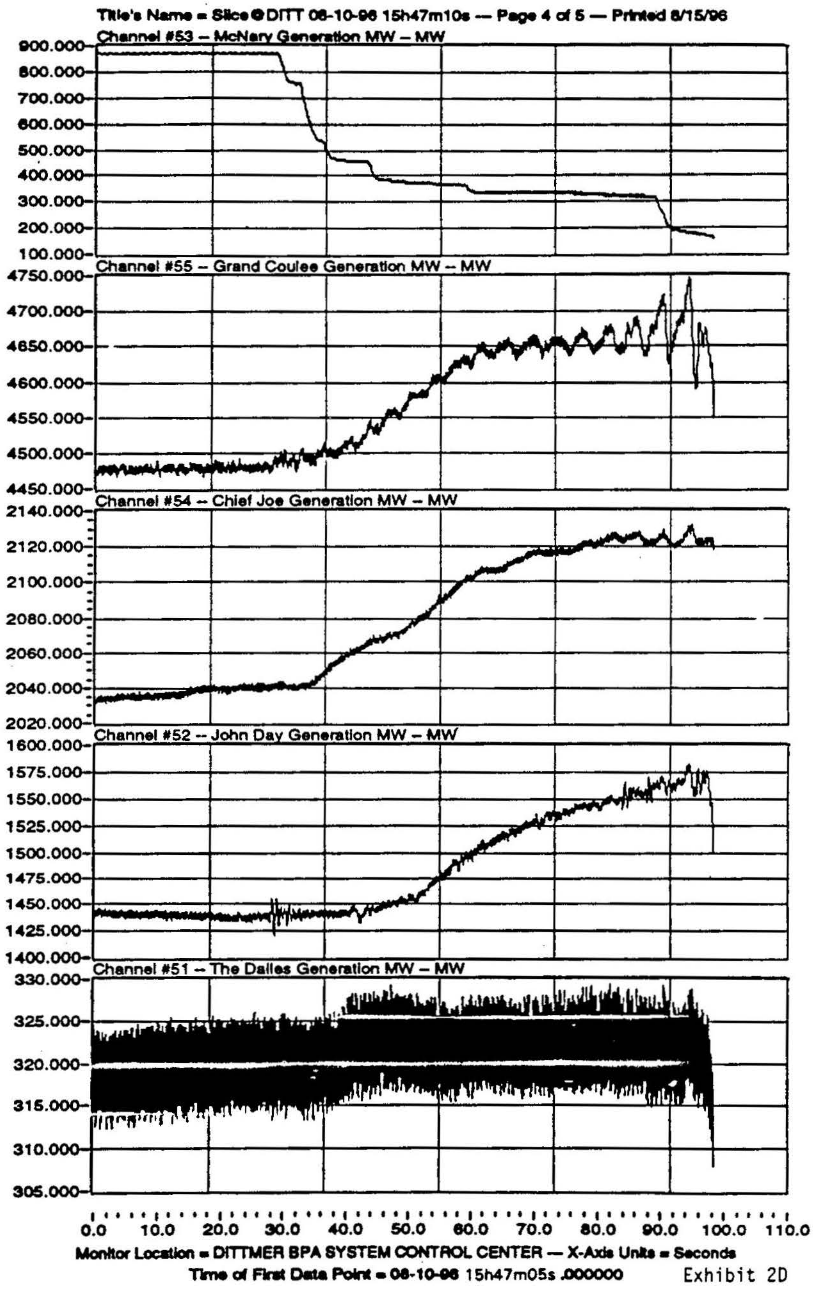
Exhibit 2C


Title's Name = Slice@DITT 08-10-96 15h47m10s — Page 4 of 5 — Printed 8/15/96
Channel #53 – McNary Generation MW – MW
900.000
800.000
700.000
600.000
500.000
400.000
300.000
200.000
100.000
Channel #55 – Grand Coulee Generation MW – MW
4750.000
4700.000
4650.000
4600.000
4550.000
4500.000
4450.000
Channel #54 – Chief Joe Generation MW – MW
2140.000
2120.000
2100.000
2080.000
2060.000
2040.000
2020.000
Channel #52 – John Day Generation MW – MW
1600.000
1575.000
1550.000
1525.000
1500.000
1475.000
1450.000
1425.000
1400.000
Channel #51 – The Dalles Generation MW – MW
330.000
325.000
320.000
315.000
310.000
305.000
0.0
10.0
20.0
30.0
40.0
50.0
60.0
70.0
80.0
90.0
100.0
110.0
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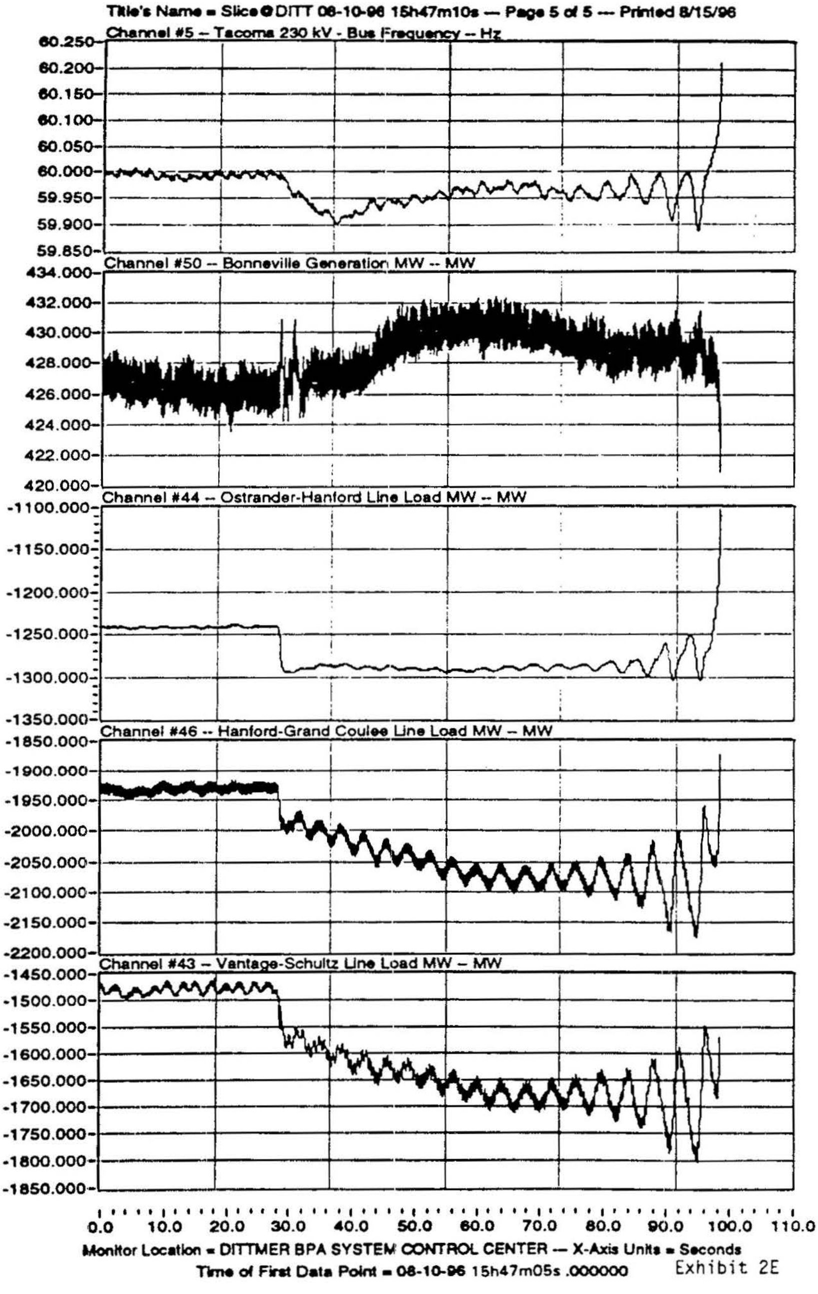
Time of First Data Point = 08-10-96 15h47m05s .000000

Exhibit 2D



Title's Name = Slice@DITT 08-10-96 15h47m10s — Page 5 of 5 — Printed 8/15/96
Channel #5 -- Tacoma 230 kV - Bus Frequency -- Hz
60.250
60.200
60.150
60.100
60.050
60.000
59.950
59.900
59.850
Channel #50 -- Bonneville Generation MW -- MW
434.000
432.000
430.000
428.000
426.000
424.000
422.000
420.000
Channel #44 -- Ostrander-Hanford Line Load MW -- MW
-1100.000
-1150.000
-1200.000
-1250.000
-1300.000
-1350.000
Channel #46 -- Hanford-Grand Coulee Line Load MW -- MW
-1850.000
-1900.000
-1950.000
-2000.000
-2050.000
-2100.000
-2150.000
-2200.000
Channel #43 -- Vantage-Schultz Line Load MW -- MW
-1450.000
-1500.000
-1550.000
-1600.000
-1650.000
-1700.000
-1750.000
-1800.000
-1850.000
0.0
10.0
20.0
30.0
40.0
50.0
60.0
70.0
80.0
90.0
100.0
110.0
Monitor Location = DITTMER BPA SYSTEM CONTROL CENTER — X-Axis Units = Seconds
Time of First Data Point = 08-10-96 15h47m05s .000000

Exhibit 2E

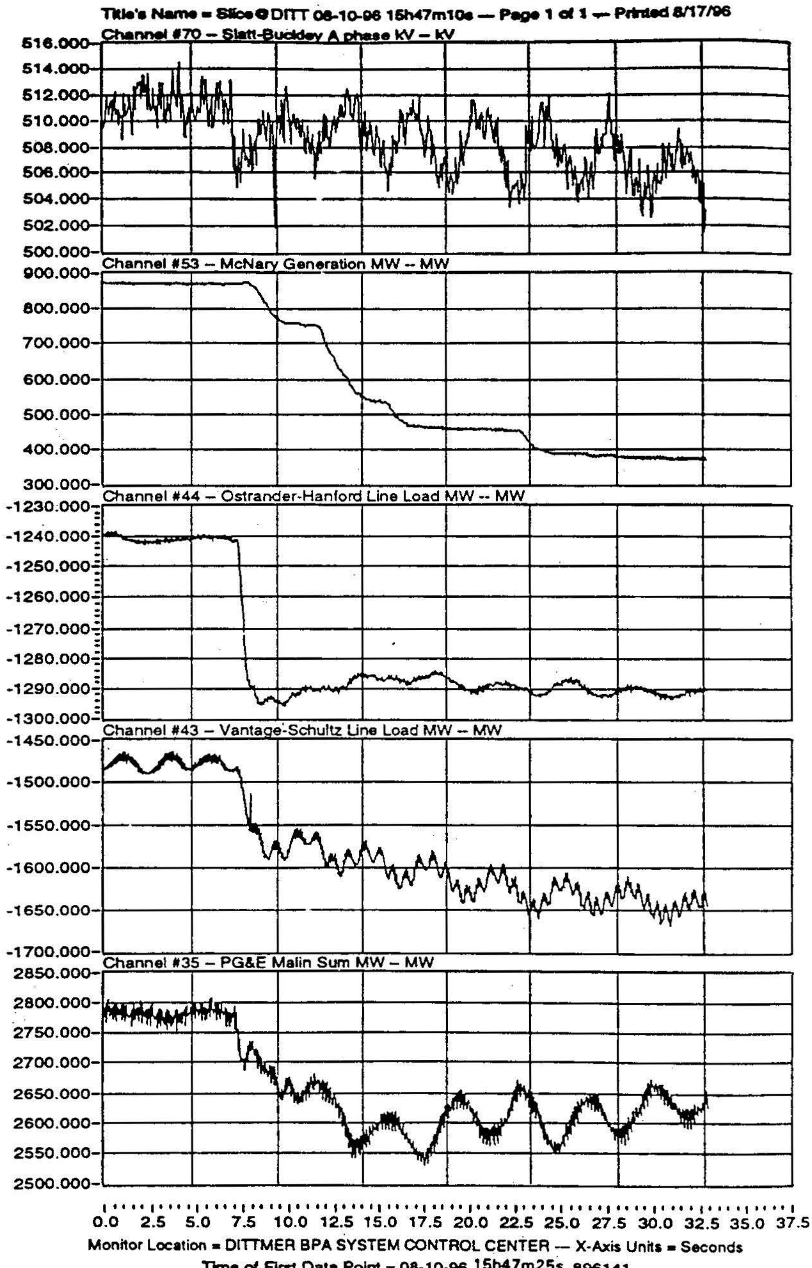

Title's Name = Slice@DITT 08-10-96 15h47m10s — Page 1 of 1 — Printed 8/17/96
Channel #70 — Slatt-Buckley A phase kV — kV
516.000
514.000
512.000
510.000
508.000
506.000
504.000
502.000
500.000
Channel #53 — McNary Generation MW — MW
900.000
800.000
700.000
600.000
500.000
400.000
300.000
Channel #44 — Ostrander-Hanford Line Load MW — MW
-1230.000
-1240.000
-1250.000
-1260.000
-1270.000
-1280.000
-1290.000
-1300.000
Channel #43 — Vantage-Schultz Line Load MW — MW
-1450.000
-1500.000
-1550.000
-1600.000
-1650.000
-1700.000
Channel #35 — PG&E Malin Sum MW — MW
2850.000
2800.000
2750.000
2700.000
2650.000
2600.000
2550.000
2500.000
0.0 2.5 5.0 7.5 10.0 12.5 15.0 17.5 20.0 22.5 25.0 27.5 30.0 32.5 35.0 37.5
Monitor Location = DITTMER BPA SYSTEM CONTROL CENTER — X-Axis Units = Seconds
Time of First Data Point = 08-10-96 15h47m25s .896141

Exhibit 2F

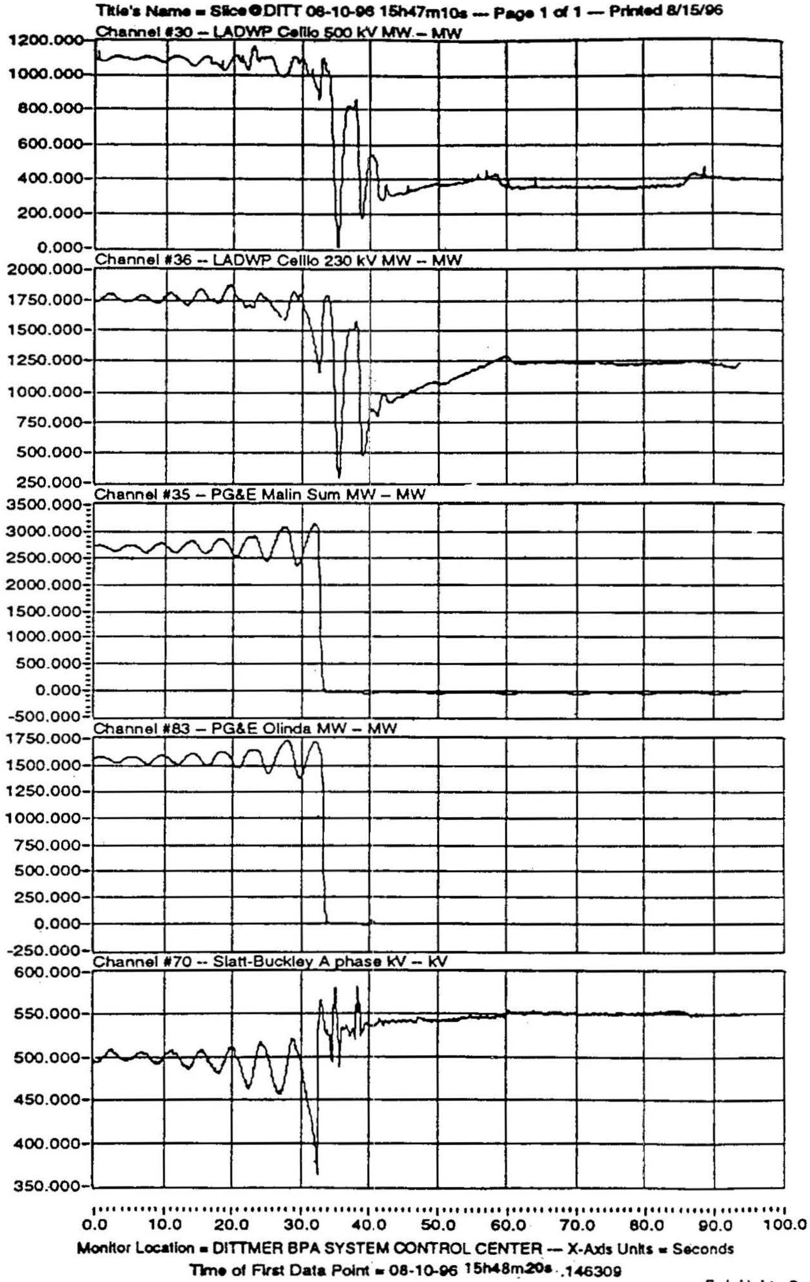

Title's Name = Slice@DITT 08-10-96 15h47m10s — Page 1 of 1 — Printed 8/15/96
Channel #30 -- LADWP Celilo 500 kV MW -- MW
1200.000
1000.000
800.000
600.000
400.000
200.000
0.000
Channel #36 -- LADWP Celilo 230 kV MW -- MW
2000.000
1750.000
1500.000
1250.000
1000.000
750.000
500.000
250.000
Channel #35 -- PG&E Malin Sum MW -- MW
3500.000
3000.000
2500.000
2000.000
1500.000
1000.000
500.000
0.000
-500.000
Channel #83 -- PG&E Olinda MW -- MW
1750.000
1500.000
1250.000
1000.000
750.000
500.000
250.000
0.000
-250.000
Channel #70 -- Slatt-Buckley A phase kV -- kV
600.000
550.000
500.000
450.000
400.000
350.000
0.0
10.0
20.0
30.0
40.0
50.0
60.0
70.0
80.0
90.0
100.0
Monitor Location = DITTMER BPA SYSTEM CONTROL CENTER — X-Axis Units = Seconds
Time of First Data Point = 08-10-96 15h48m20s .146309

Exhibit 3

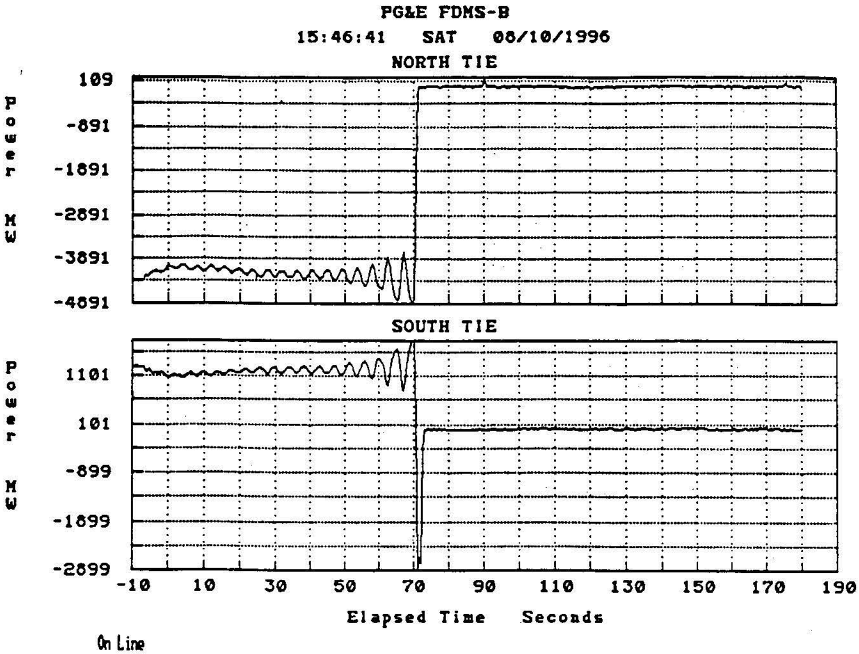

PG&E FDMS-B
15:46:41 SAT 08/10/1996
NORTH TIE
Power MW
109
-891
-1891
-2891
-3891
-4891
SOUTH TIE
Power MW
1101
101
-899
-1899
-2899
-10
10
30
50
70
90
110
130
150
170
190
Elapsed Time Seconds
On Line

Exhibit 4

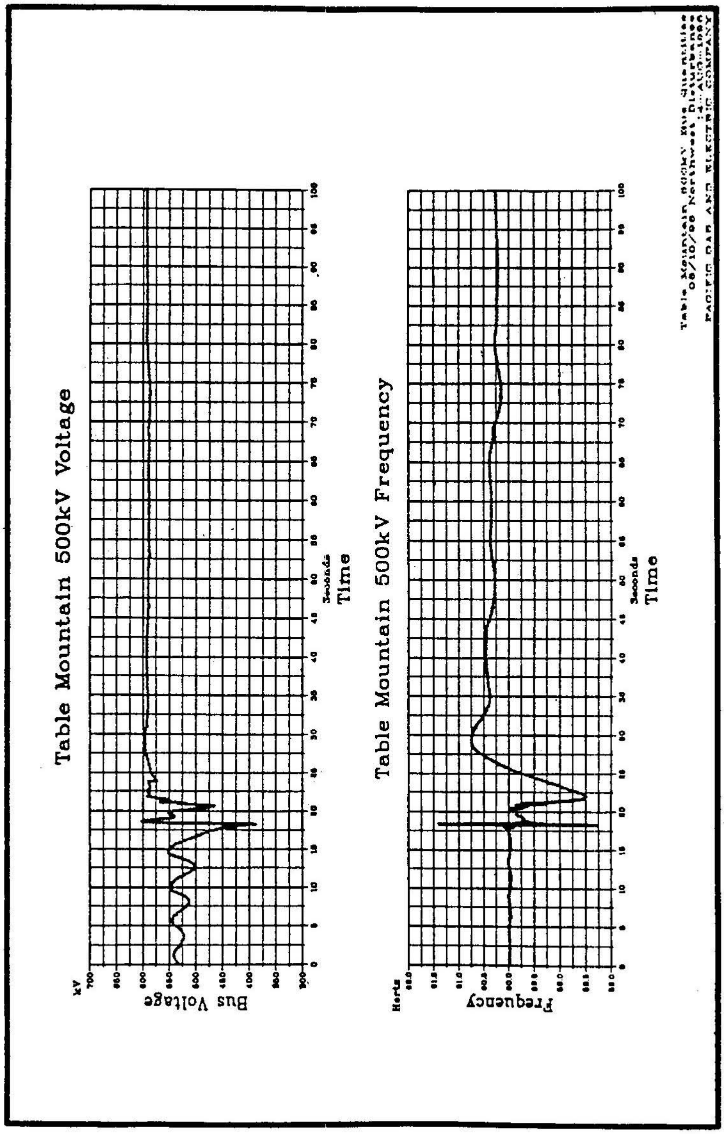


Table Mountain 500kV Voltage
Bus Voltage
kV
Seconds
Time
Table Mountain 500kV Frequency
Frequency
Hertz
Seconds
Time

Exhibit 5A

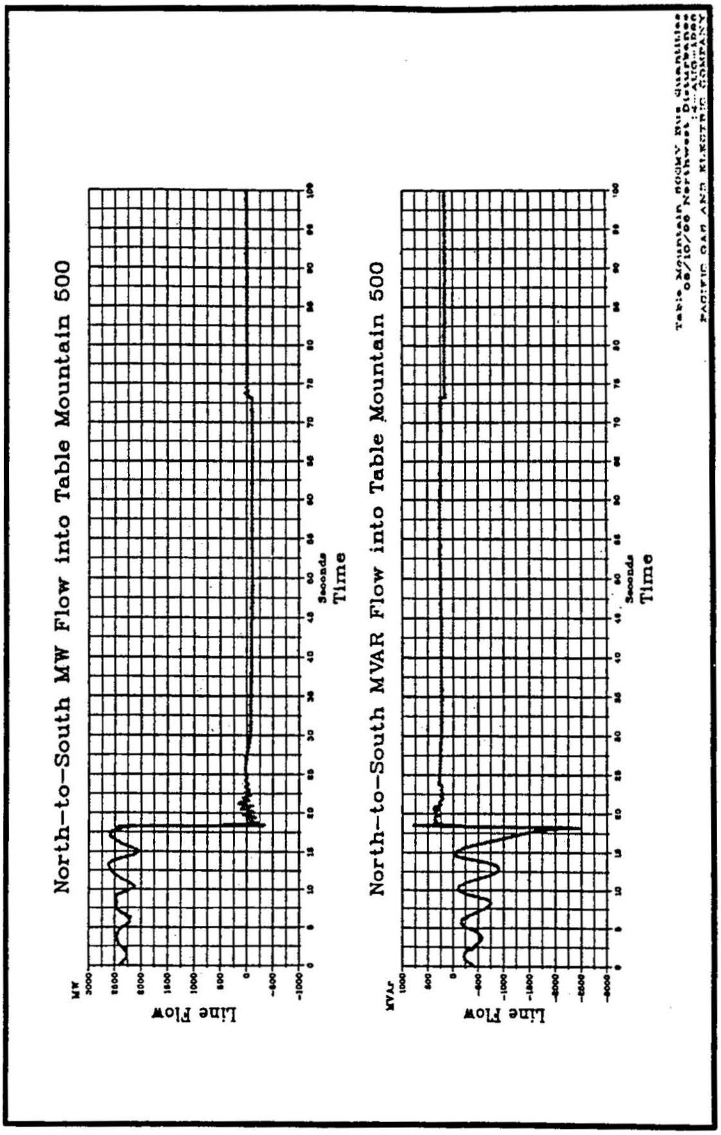

North-to-South MW Flow into Table Mountain 500
Line Flow
MW
Seconds
Time
North-to-South MVAR Flow into Table Mountain 500
Line Flow
MVAr
Seconds
Time

Exhibit 5B

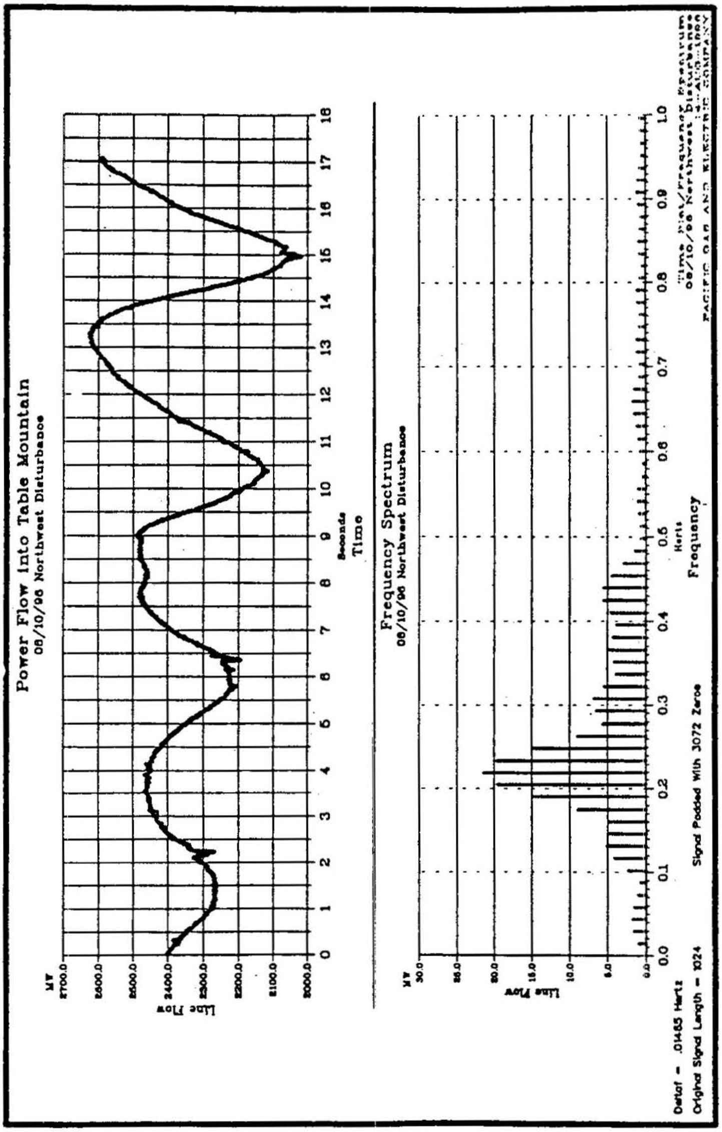

Power Flow Into Table Mountain
08/10/96 Northwest Disturbance
MW
Line Flow
Seconds
Time
Frequency Spectrum
08/10/96 Northwest Disturbance
Hertz
Frequency
Deltaf = .01465 Hertz
Original Signal Length = 1024
Signal Padded With 3072 Zeros
PACIFIC GAS AND ELECTRIC COMPANY

Exhibit 5C

McNary-Total MVar Output

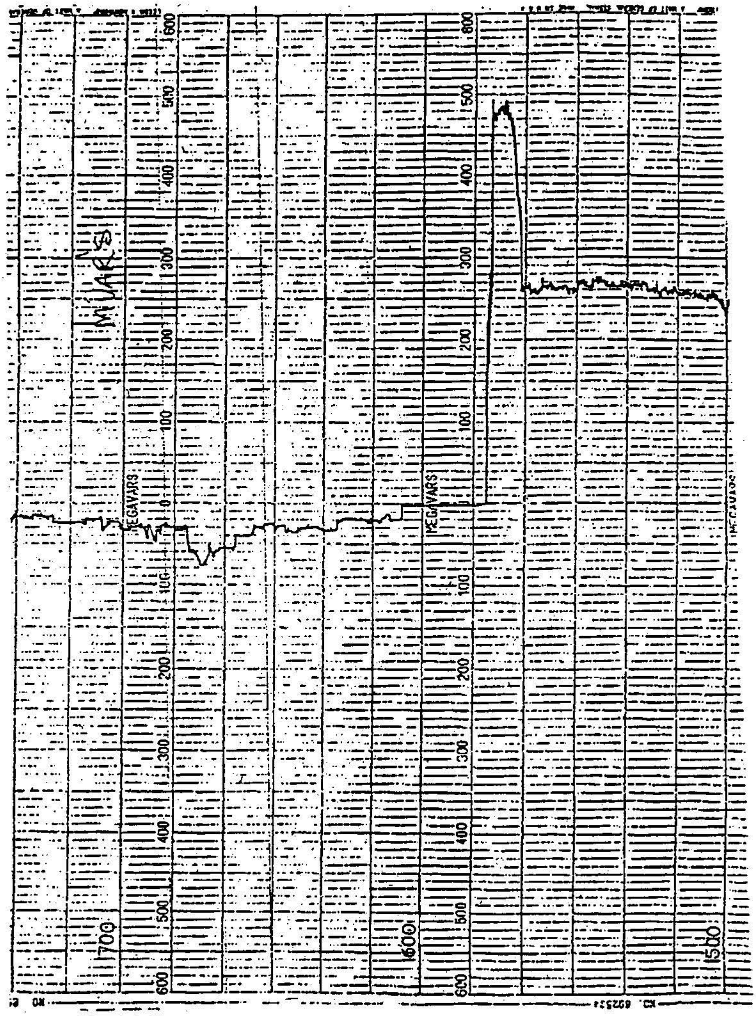
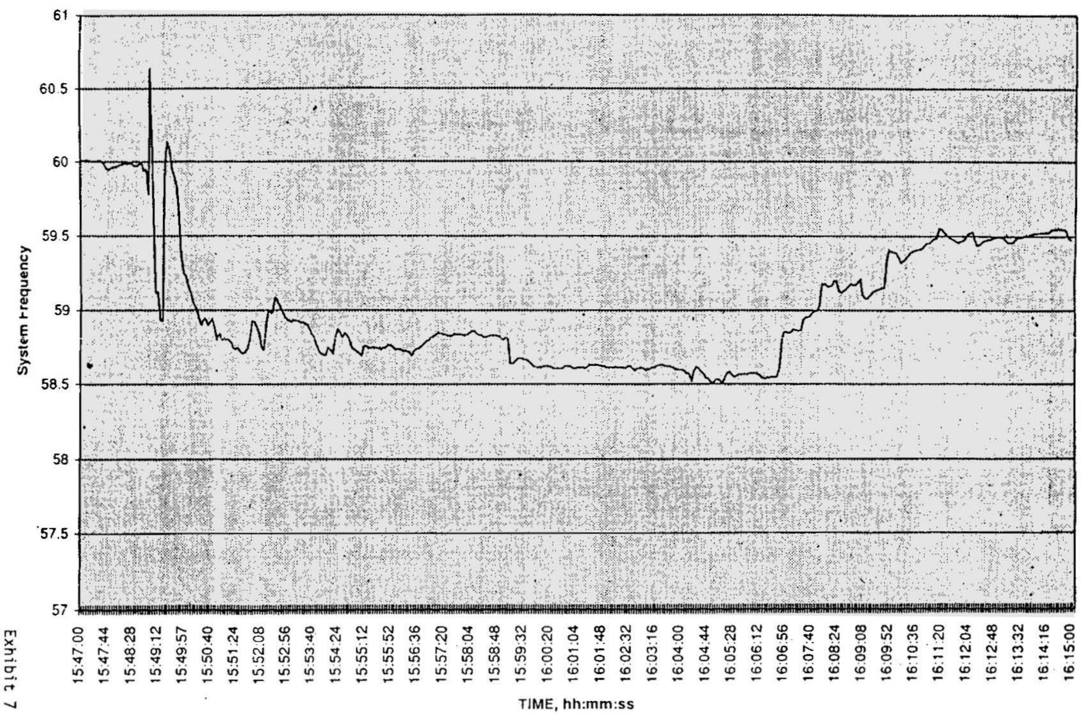


Exhibit 6

AUGUST 10,1996 System D   urbance, SCE Area Frequency



Note: Frequency data were scanned at 4 seconds sampling period. There was an indication of SCE system frequency at 61.3 HZ within very short period occured at 15:48:55.500

Exhibit 7

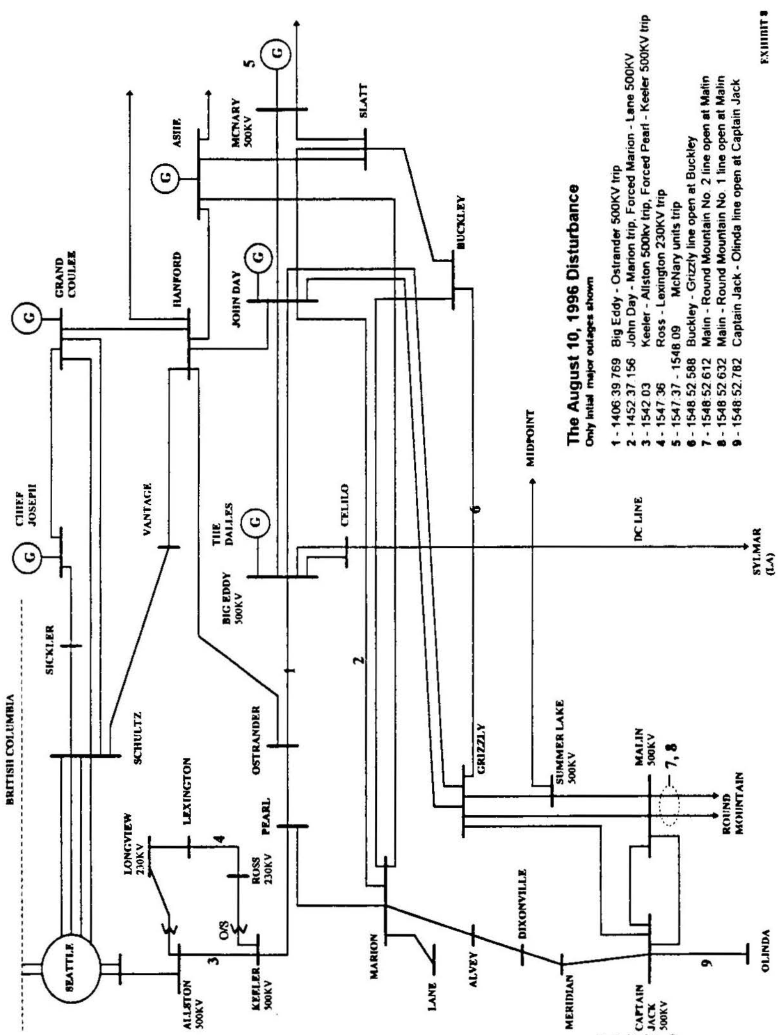

BRITISH COLUMBIA
SEATTLE
SICKLER
SCHULTZ
CHIEF JOSEPH
G
GRAND COULEE
VANTAGE
HANFORD
ASHE
MCNARY 500KV
5
SLATT
JOHN DAY
BUCKLEY
THE DALLES
CELILO
BIG EDDY 500KV
1
2
6
OSTRANDER
PEARL
LONGVIEW 230KV
LEXINGTON
4
ROSS 230KV
O/S
3
ALLSTON 500KV
KEELER 500KV
MARION
LANE
ALVEY
DIXONVILLE
MERIDIAN
CAPTAIN JACK 500KV
9
OLINDA
GRIZZLY
SUMMER LAKE 500KV
MALIN 500KV
7, 8
ROUND MOUNTAIN
MIDPOINT
DC LINE
SYLMAR (LA)
The August 10, 1996 Disturbance
Only intial major outages shown
1 - 1406:39.769 Big Eddy - Ostrander 500KV trip
2 - 1452:37.156 John Day - Marion trip, Forced Marion - Lane 500KV
3 - 1542:03 Keeler - Allston 500kv trip, Forced Pearl - Keeler 500KV trip
4 - 1547:36 Ross - Lexington 230KV trip
5 - 1547:37 - 1548:09 McNary units trip
6 - 1548:52.588 Buckley - Grizzly line open at Buckley
7 - 1548:52.612 Malin - Round Mountain No. 2 line open at Malin
8 - 1548:52.632 Malin - Round Mountain No. 1 line open at Malin
9 - 1548:52.782 Captain Jack - Olinda line open at Captain Jack
EXHIBIT 8

Exhibit 8

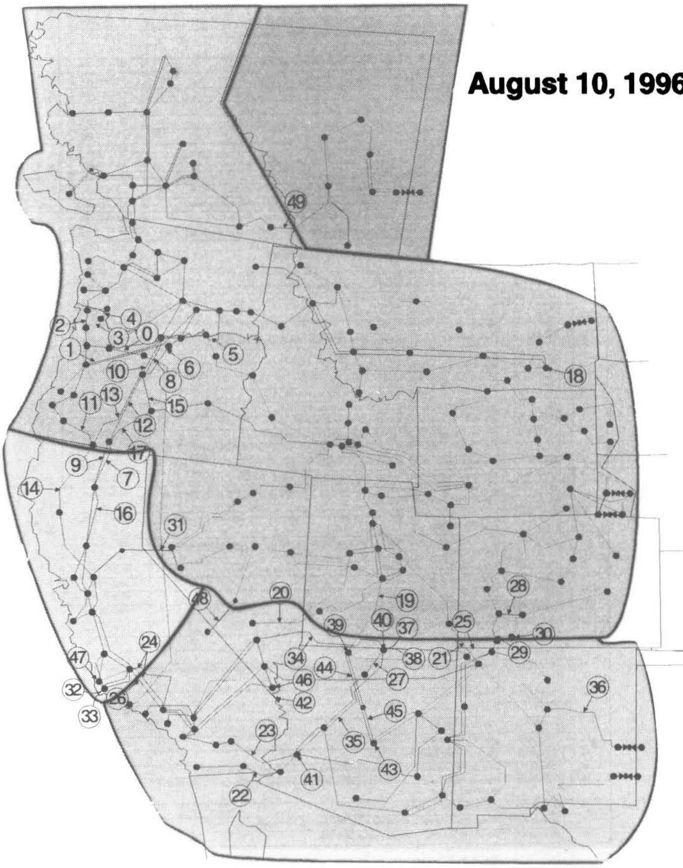
Exhibit 9

Significant Events Leading to System Separation

Map Showing Sequence of System Separation

SEQUENCE OF SIGNIFICANT EVENTS - AUGUST 10, 1996			
EVENT NUMBER	TIME	EVENT	Difference from Time = 0 hh:mm:ss.000
0	14:06:39.769	Big Eddy-Ostrander 500-kV single phase-to-ground fault, relayed 3-pole trip. Flashed to tree.	00:00:00.000
1	14:52:37.156	John Day-Marion 500-kV single phase-to-ground fault. Flashed to tree.	00:45:57.387
2	15:42:03.139	Keeler-Allston 500-kV single phase-to-ground fault; tripped single pole with unsuccessful reclose. Flashed to tree.	01:35:23.370
3	15:47:29	Merwin-St. Johns 115-kV line tripped on relay misoperation (Note: time is approximate)	01:40:49:231
4	15:47:36	Fault on Ross-Lexington 230-kV line. Flashed to tree. Fault started small fire. (BEGINNING OF DISTURBANCE)	01:40:56.231
5	15:47:36	McNary trips 117 MW (2 units) - (Timing from event 4 for rest of table)	00:00:00.000
	15:47:40	McNary trips 215 MW (3 units)	00:00:04.000
	15:47:44	McNary trips 75 MW (1 unit)	00:00:08.000
	15:47:52	McNary trip (1 unit)	00:00:16.000
	15:48:09	McNary trip (1 unit)	00:00:33:000
6	15:48:52.588	Buckley-Grizzly 500-kV line open at Buckley.	00:01:16.588
7	15:48:52.613	Malin-Round Mountain No. 2 500-kV line open at Malin.	00:01:16.613
8	15:48:52.618	John Day-Grizzly No. 1 500-kV line open at John Day; open at Grizzly at 52.633.	00:01:16.618
9	15:48:52.632	Malin-Round Mountain No. 1 500-kV line open at Malin.	00:01:16.632
10	15:48:52.641	John Day-Grizzly No. 2 500-kV line open at Grizzly; open at John Day at 52.654.	00:01:16.641
11	15:48:52.682	Captain Jack-Meridian 500-kV line open at Captain Jack (PCB 4983,4986), reclose blocked.	00:01:16.682
12	15:48:52.740	Grizzly-Malin No. 2 500-kV line open at Grizzly (PCB 4048); open at Malin at 52.750.	00:01:16.740
13	15:48:52.778	Captain Jack-Grizzly 500-kV line open at Captain Jack (PCB 4993,4990); Grizzly open at 52.794.	00:01:16.778
14	15:48:52.782	Captain Jack-Olinda 500-kV line open at Captain Jack (PCB 4977,4980). (COI NOW OPEN BETWEEN OREGON AND CALIFORNIA)	00:01:16.782
15	15:48:52.878	Grizzly-Summer Lake 500-kV line open at Grizzly; open at Summer Lake at 52.907.	00:01:16.878
16	15:48:53.000	Round Mountain-Table Mountain No. 2 500-kV line open ended at Round Mountain.	00:01:17.000
17	15:48:53.255	Malin-Summer Lake 500-kV line opens at Summer Lake; Malin terminal opens at 53.258.	00:01:17.255
18	15:48:53.622	Colstrip Unit Nos. 3 and 4 relayed off-line.	00:01:17.622
	15:48:53.649	Colstrip Unit No. 1 relayed off-line.	00:01:17.649
19	15:48:53.708	Sigurd terminal of the Glen Canyon-Sigurd 230-kV line relayed. Out-of step trip.	00:01:17.708
20	15:48:53.930	Red Butte-Harry Allen 345-kV line opens, out-of-step.	00:01:17.930
21	15:48:54.415	Four Corners-Pinto 345-kV line (at Four Corners).	00:01:18.415
22	15:48:54.576	North Gila-Imperial Valley 500-kV line tripped.	00:01:18.576
23	15:48:54.622	Palo Verde-Devers 500-kV tripped at Palo Verde; at Devers at 54.625.	00:01:18.622
24	15:48:54.700	Midway-Vincent Nos. 1 and 2 500-kV lines tripped, out-of-step.	00:01:18.700
25	15:48:54.703	Shiprock-Lost Canyon 230-kV line relayed, out-of-step trip.	00:01:18.703
26	15:48:54.765	Midway-Vincent No. 3 500-kV line tripped due to voltage collapse. (NORTHERN CALIFORNIA NOW SEPARATED FROM SOUTHERN CALIFORNIA)	00:01:18.765
27	15:48:54.825	Navajo-Moenkopi 500-kV line at Navajo.	00:01:18.825
28	15:48:54.846	Curecanti terminal of the Curecanti-Montrose 115-kV line relayed. ZONE 1	00:01:18.846
29	15:48:54.936	Hesperus terminal of the Waterflow-Hesperus 345-kV line and both terminals of Montrose-Hesperus 345-kV line relayed, out-of-step trip.	00:01:18.936
30	15:48:54.938	City of Farmington, NM, Glade Tap-Durango 115-kV tie opened at Glade Tap: out-of-step trip (2 paths now open).	00:01:18.938
31	15:48:55	North Truckee-Summit 120-kV line, California-Summit 120-kV line, and Truckee-Tahoe Donner 60-kV line tripped.	00:01:19.000
32	15:48:55.141	Diablo Canyon Unit No. 2 tripped.	00:01:19.141
33	15:48:55.405	Diablo Canyon Unit No. 1 tripped.	00:01:19.405
34	15:48:58.496	Navajo-McCullough 500-kV line at Najavo.	00:01:22.496
35	15:48:58.803	Navajo-Westwing 500-kV line at Najavo.	00:01:22.803
36	15:48:59.000	BB 345-kV line and Blackwater DC Converter tripped.	00:01:23.000
37	15:48:59.341	Navajo Unit No. 1.	00:01:23.341
38	15:48:59.492	Navajo Unit No. 2.	00:01:23.492
39	15:49:00.000	Glen Canyon Unit Nos. 2, 5, 7, and 8 tripped via remedial action scheme while carrying approximately 430 MW. Caused by loss of both Glen Canyon-Flagstaff 345-kV lines.	00:01:24.000
40	15:49:07.140	Navajo Unit No. 3.	00:01:31.140
41	15:49:13.315	Palo Verde Unit No. 1.	00:01:37.315
	15:49:13.405	Palo Verde Unit No. 3.	00:01:37.405
42	15:49:14.000	Hoover Dam: Units 2, 3, and 8 relayed.	00:01:38.000
43	15:49:20.830	Pinnacle Peak-Pinnacle Peak (WAPA).	00:01:44.830
44	15:49:45.271	Glen Canyon terminals of the Glen Canyon-Flagstaff Nos. 1 and 2 345-kV lines relayed.	00:02:09.271
45	15:49:48.000	Pinnacle Peak: Flagstaff-PPK No. 1 Line PCBs 1092 and 1196 relayed. Flagstaff-PPK No. 2 Line PCBs 1492 and 1596 relayed.	00:02:12.000
46	15:49:59.723	Mohave Unit No. 2 tripped.	00:02:23.723
47	15:50:00.000	Hunters Point Unit No. 2 relayed and Morro Bay Unit Nos. 1-4 relayed.	00:02:24.000
48	15:50:00.000	Silver Peak 55-kV SCB/SPP tie tripped at Silver Peak.	00:02:24.000
49	15:54	Cranbrook-Langdon 500-kV line. (FINAL SYSTEM SEPARATION)	00:06:24.000

Sequence of Significant Events



Islands Formed August 10, 1996

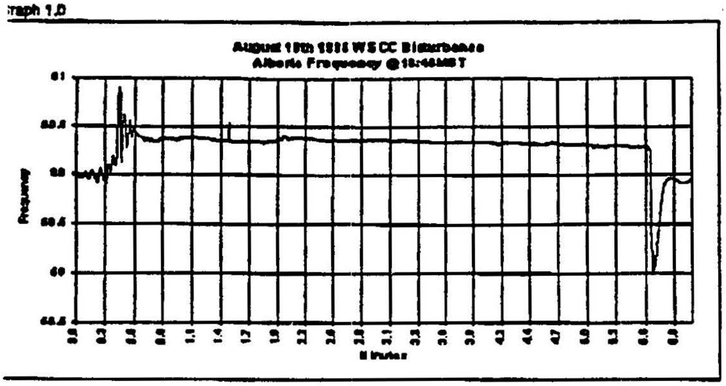
Exhibit 10

BCHA-Alberta Power Transfer

Frequency Plots for Alberta

BPA Frequency/Time Error Plots

Graph 1.0



Graph 2.0

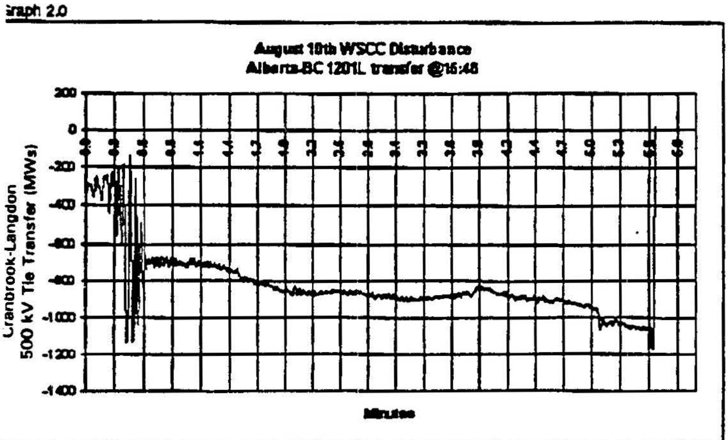
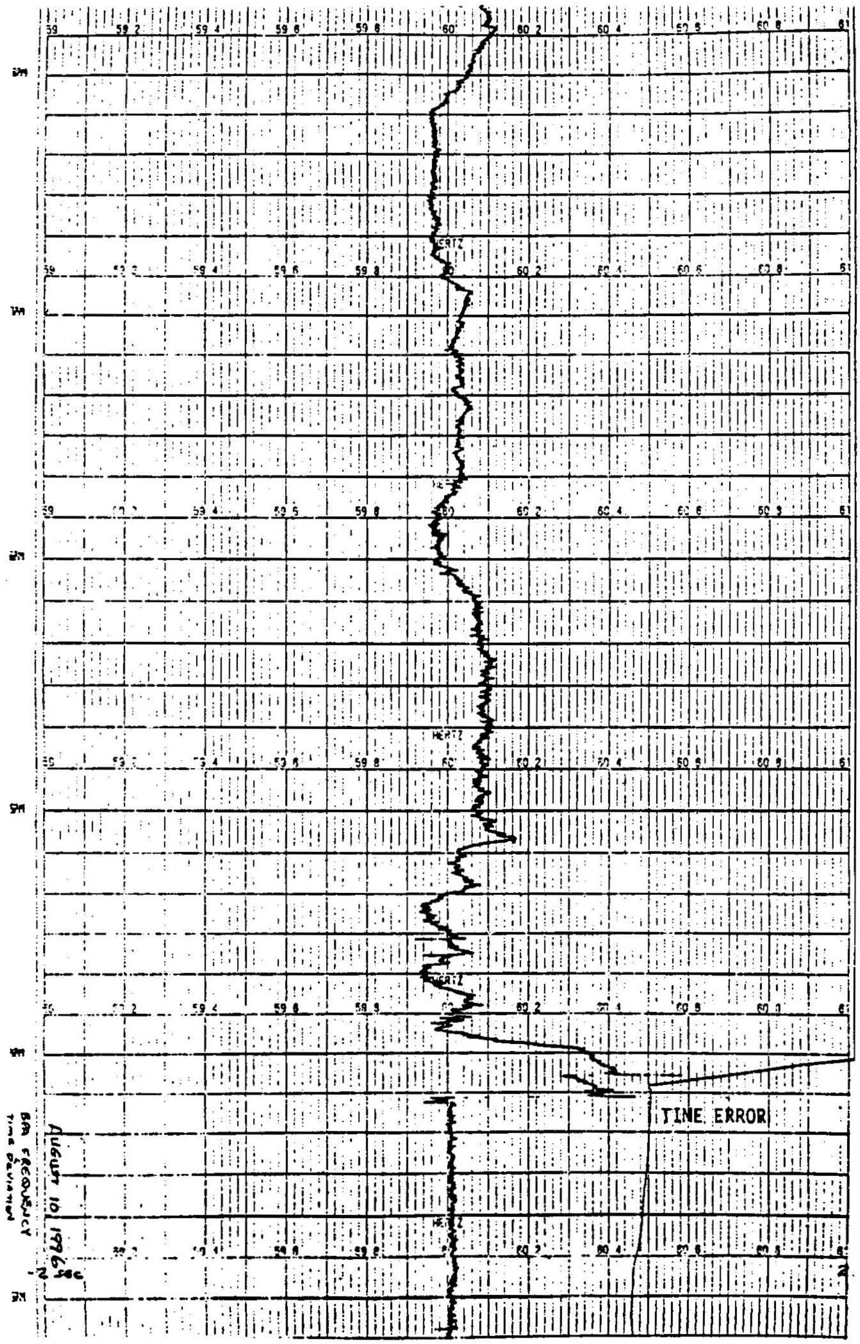
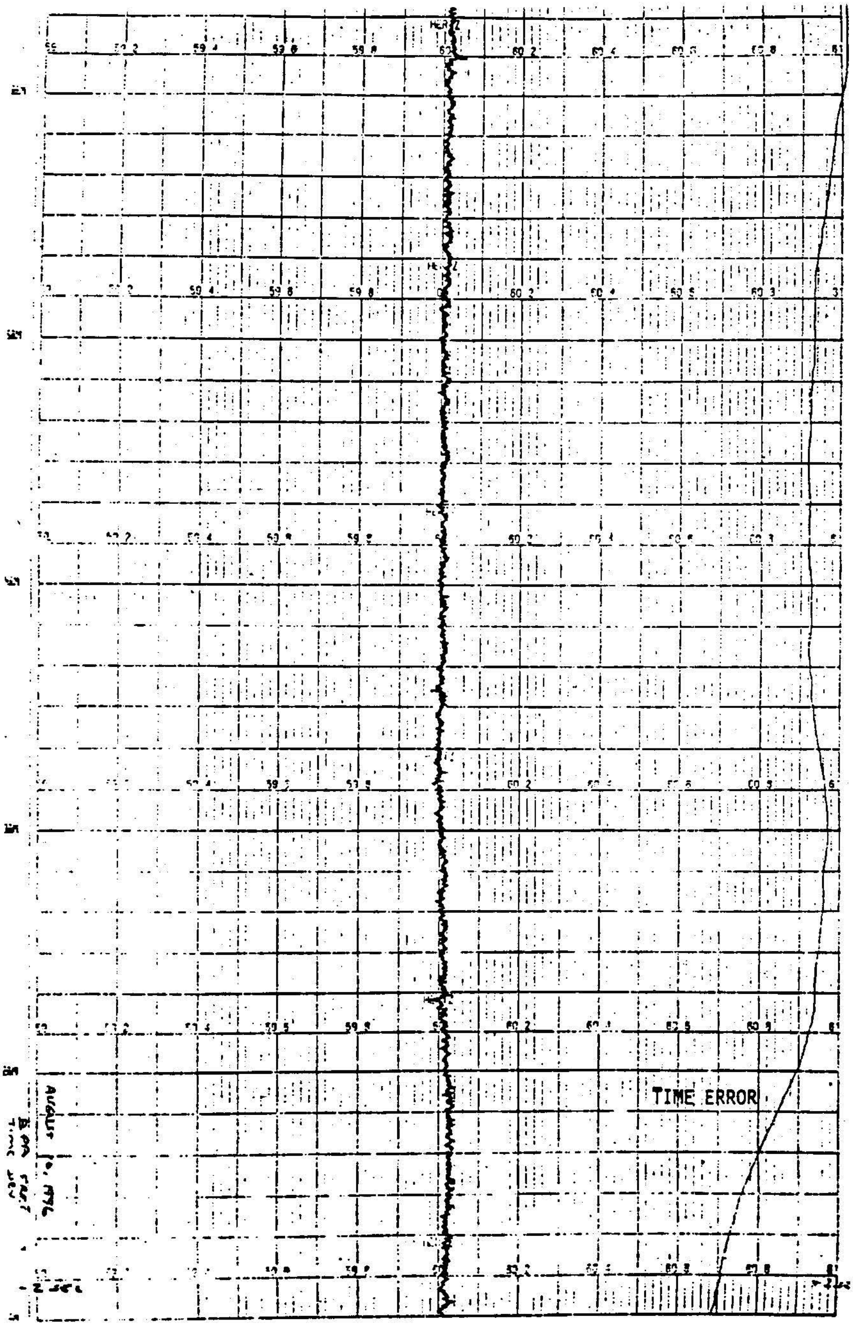
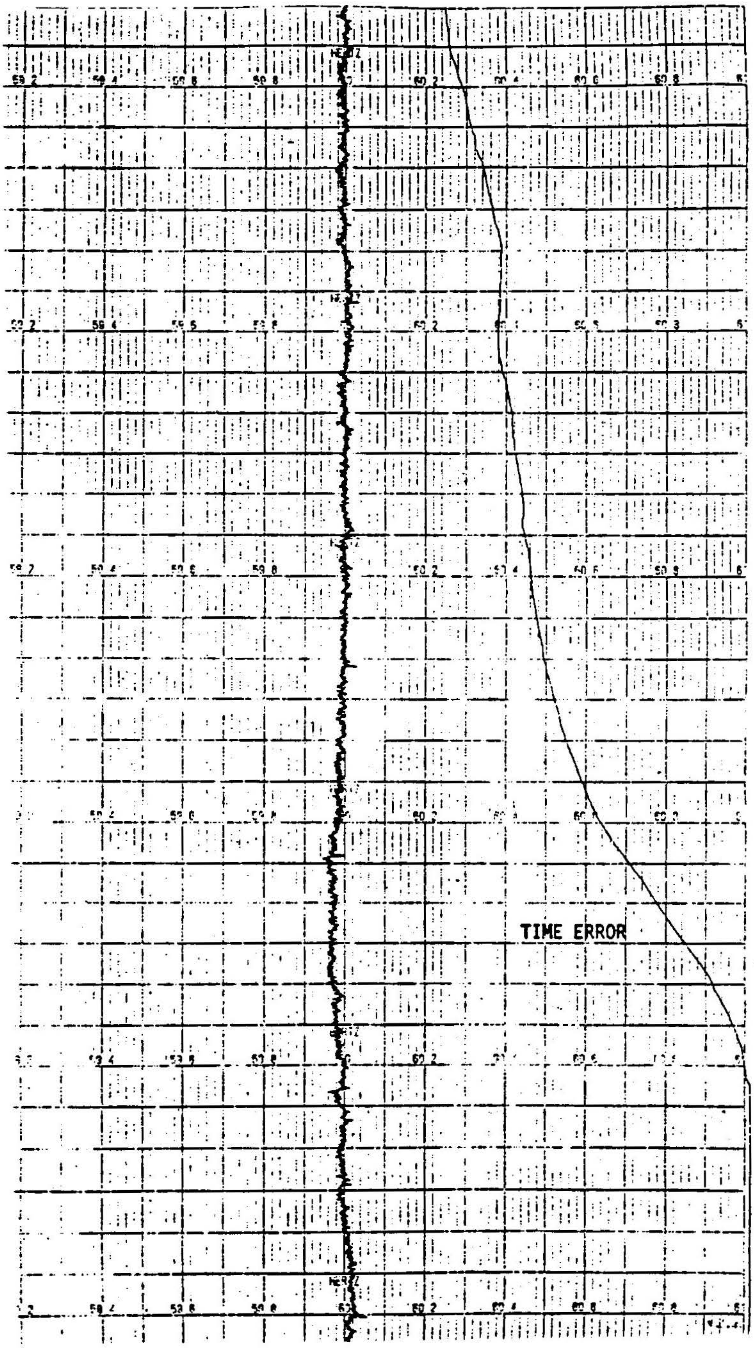
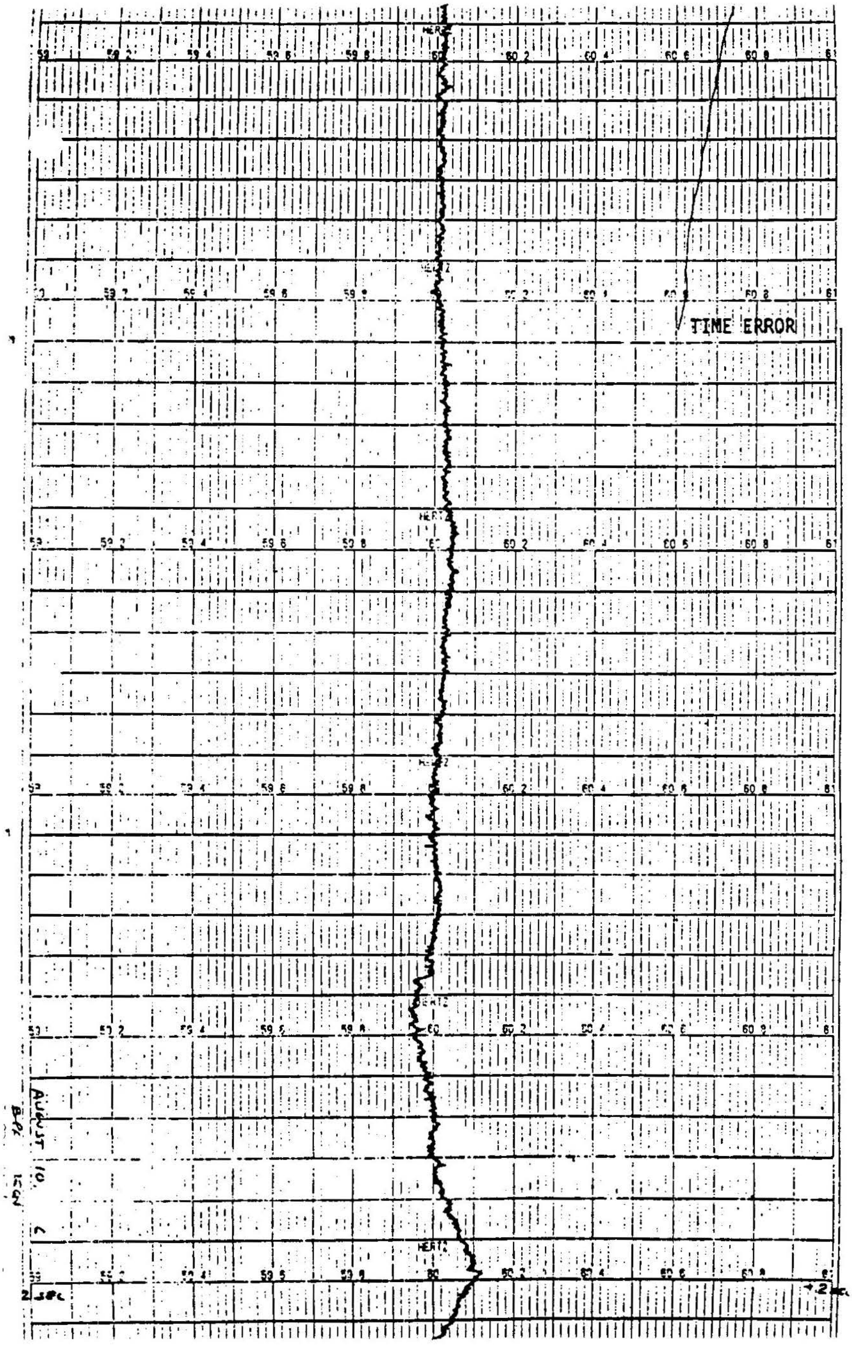


Exhibit 10


HERTZ
TIME ERROR
BPA FREQUENCY & TIME DEVIATION
AUGUST 10 1996
2 SEC


HERTZ
59.4
59.8
60.2
60.4
TIME ERROR
AUGUST


HERTZ
TIME ERROR


HERTZ
59 59.2 59.4 59.6 59.8 60 60.2 60.4 60.6 60.8 61
TIME ERROR

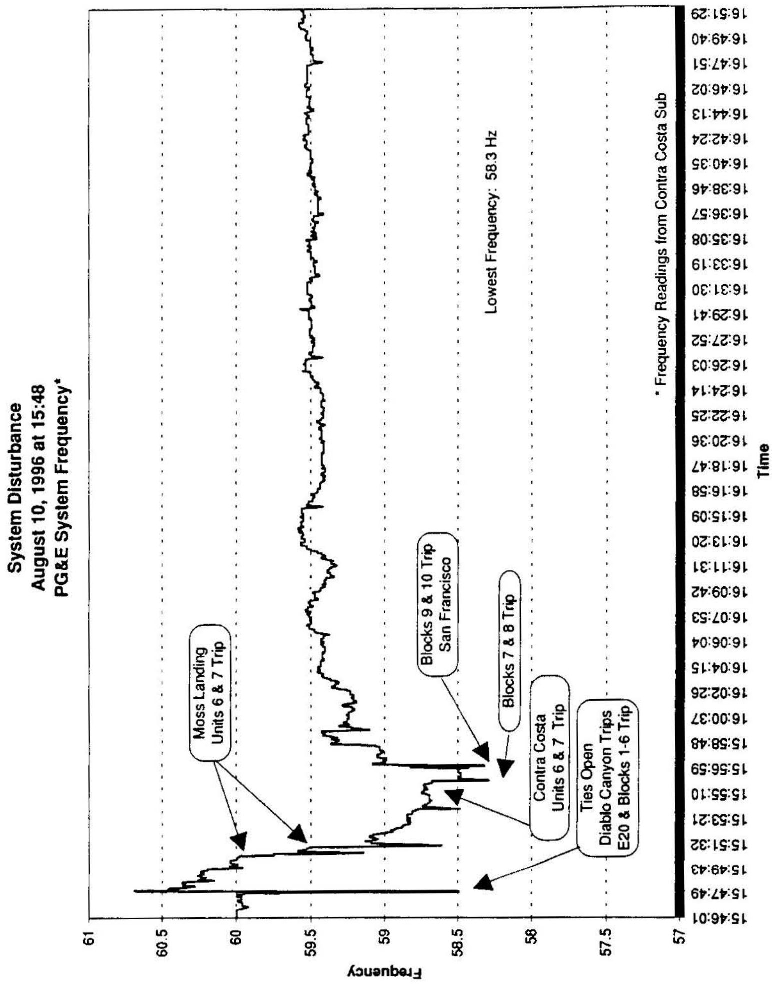

System Disturbance
August 10, 1996 at 15:48
PG&E System Frequency*
Moss Landing
Units 6 & 7 Trip
Blocks 9 & 10 Trip
San Francisco
Blocks 7 & 8 Trip
Contra Costa
Units 6 & 7 Trip
Ties Open
Diablo Canyon Trips
E20 & Blocks 1-6 Trip
Lowest Frequency: 58.3 Hz
* Frequency Readings from Contra Costa Sub
Frequency
Time
61
60.5
60
59.5
59
58.5
58
57.5
57
15:46:01
15:47:49
15:49:43
15:51:32
15:53:21
15:55:10
15:56:59
15:58:48
16:00:37
16:02:26
16:04:15
16:06:04
16:07:53
16:09:42
16:11:31
16:13:20
16:15:09
16:16:58
16:18:47
16:20:36
16:22:25
16:24:14
16:26:03
16:27:52
16:29:41
16:31:30
16:33:19
16:35:08
16:36:57
16:38:46
16:40:35
16:42:24
16:44:13
16:46:02
16:47:51
16:49:40
16:51:29

EXHIBIT 11

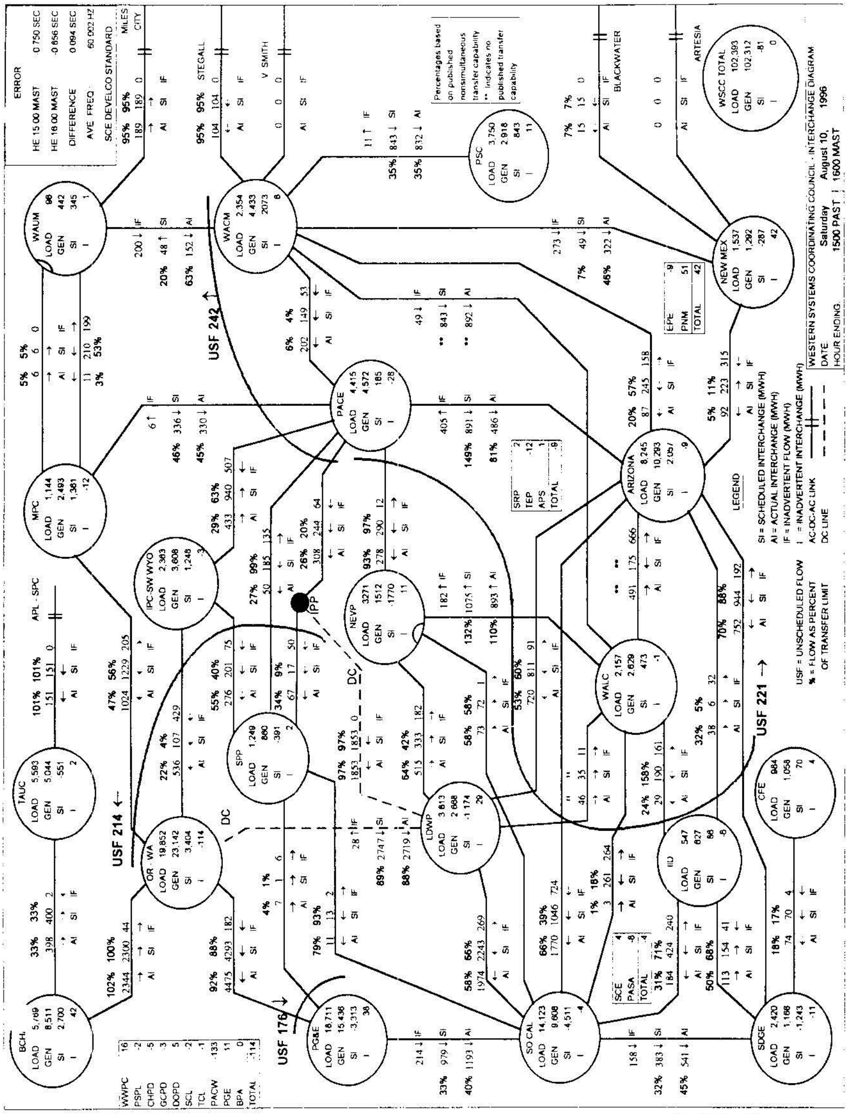

WESTERN SYSTEMS COORDINATING COUNCIL - INTERCHANGE DIAGRAM
DATE Saturday August 10, 1996
HOUR ENDING 1500 PAST / 1600 MAST
LEGEND
SI = SCHEDULED INTERCHANGE (MWH)
AI = ACTUAL INTERCHANGE (MWH)
IF = INADVERTENT FLOW (MWH)
I = INADVERTENT INTERCHANGE (MWH)
AC-DC-AC LINK
DC LINE
USF = UNSCHEDULED FLOW
% = FLOW AS PERCENT OF TRANSFER LIMIT
Percentages based on published nonsimultaneous transfer capability
** Indicates no published transfer capability
ERROR
HE 15 00 MAST 0 750 SEC
HE 16 00 MAST -0 656 SEC
DIFFERENCE 0 094 SEC
AVE FREQ 60 002 HZ
SCE DEVELCO STANDARD
WSCC TOTAL
LOAD 102,393
GEN 102,312
SI -81
USF 214
USF 242
USF 176
USF 221
BCH
TAUC
OR - WA
MPC
WAUM
WACM
PACE
IPC-SW WYO
SPP
NEVP
LDWP
PG&E
SO CAL
SDGE
IID
CFE
WALC
ARIZONA
NEW MEX
PSC
IPP
DC
MILES CITY
STEGALL
V SMITH
BLACKWATER
ARTESIA
APL - SPC

Exhibit 10

Form Rev. 11-1-93

1996

OPERATING SUPPLEMENTAL LINE FLOW REPORT

	Saturday August 10 1500 PAST
1. East of the Colorado River	
* Navajo-McCullough 500 kV	714
Moenkopi-*Eldorado 500 kV	856
*Palo Verde-Devers 500 kV	922
*Palo Verde-North Gila 500 kV	0
*Liberty-Mead 345 kV	-177
NETTED TOTAL (E to W)	2,315
2. Northwest of the Colorado River	
*McCullough-Victorville #1 500 kV	333
*McCullough-Victorville #2 500 kV	322
*Hoover-Victorville 287 kV	21
*Eldorado-Lugo 500 kV	477
*Eldorado-Lugo #1 230 kV	15
*Eldorado-Lugo #2 230 kV	15
*Mohave-Lugo 500 kV	662
J. Hinds-*Devers 230 kV	39
NETTED TOTAL (E to W)	1,884
3. NE/SE Boundary Break Point	
Pinto-*Four Corners 345 kV	416
Lost Canyon-Shiprock 230 kV	159
Durango-Shiprock 115 kV	-28
Waterflow-San Juan 345 kV	333
Sigurd-Glen Canyon 230 kV	151
Red Butte-Harry Allen 345 kV	279
NETTED TOTAL (N to S)	1,310
4. Total 1A'	
Bears Ears-Bonanza 345 kV	357
*Hayden-Artesia 138 kV	29
*Meeker-Southwest Rangely 138 kV	-12
NETTED TOTAL (E to W)	374
5. Total 2A	
Lost Canyon-*Shiprock 230 kV	159
Durango-*Shiprock 115 kV	-28
Waterflow-*San Juan 345 kV	333
NETTED TOTAL (From Tot 2A)	464
6. Total 4A (Wyoming)	
**Dave Johnston-Difficulty 230 kV	NA
**Riverton-Wyopo 230 kV	NA
Spence-Mustang 230 kV	NA
NETTED TOTAL (N to S)	373

7. West of Taft	
*Taft-Bell 500 kV	121
*Taft-Dworshak 500 kV	1112
NETTED TOTAL (E to W)	1,233
8. Four Corners Area	
*Four Corners-Moenkopi 500 kV	1075
*Four Corners-Cholla #1 & #2 345 kV	991
NETTED TOTAL (E to W)	2,066
9. South of Table Mountain	
*Table Mountain-Vaca Dixon 500 kV	1380
*Table Mountain-Tesla 500 kV	1327
NETTED TOTAL (N to S)	2,707
10. Other Flows	
*N. Gila-Imperial Valley 500 kV	755
*Devers-Valley 500 kV	228
Midpoint-Summer Lake	628

11. Phase Shifters

A. Saturday -- 1500 PST	Check if Bypassed	Phase Angle	Schedule (MW)	Actual (MW)
Lost Canyon-Shiprock 230 kV		+1		159
Waterflow-San Juan 345 kV		-1	454	333
Sigurd-Glen Canyon 230 kV		+5	31	151
Pinto-Four Corners 345 kV		+3	515	110
Red Butte-Harry Allen 345 kV				
Billings-Yellowtail 161 kV		+1		
Billings-Yellowtail 230 kV		+1	-210	74
Crossover-Yellowtail 230 kV		0		

* Metered end.

** Instantaneous reading.

\+ All readings assumed positive unless prefixed by a minus (-) sign. Positive shows power flow <u>from</u> the terminal listed on the left <u>to</u> the terminal listed on the right.

Negative indicates power flow <u>from</u> the terminal listed on the right <u>to</u> the terminal listed on the left.

Refer any questions on this report to Larry Harmon, WSCC Staff (801) 582-0353.

Appendix 1

Customers Affected and Load Lost

Appendix 1

Summary of Load Lost and Customers Interrupted
August 10, 1996

ISLAND	FIRM (MW)	INTERRUPTIBLE (MW)	TOTAL LOAD (MW)	CUSTOMERS	ENERGY (MW-min)
NORTHERN CALIFORNIA	11,302	300	11,602	2,892,343	388,017
SOUTHERN	15,231	589	15,820	4,195,972	1,975,864
NORTHERN	1,791	308	2,099	209,858	95,075
ALBERTA	761	207	968	191,904	24,888
TOTAL	29,085	1,404	30,489	7,490,077	2,483,844

Northern California Island

Appendix 1

MEMBER	FIRM (MW)	INTERRUPTIBLE (MW)	TIME INTERRUPTED	REASON	NUMBER OF CUSTOMERS	TIME RESTORED	MW-MINUTE LOAD LOST
CDWR		Pump Load 598	1548	RAS	N/A	N/A	N/A
MID	162		1548:56	underfrequency	31,000	2002	40,986
NCPA	273.1		1548	disturbance	4,405	1700	
					2,005	1800	
					65,500	2100	
PG&E		300	1547:52:00	59.75 Hz	120	2042	88,840
	5700	<—Block 1-6 (30%)	1547:55:00	59.3 - 58.7 Hz	2,000,000	1552:25:00	25,650
	1900	<—Blocks 7 & 8 (10%)	1554:00:00	58.5 Hz		1559:30:00	8,550
	1737	<—Block 9 & 10 (partial)	1556:03:00	58.3 Hz	494,128	1600:33:00	7,817
SMUD	72.80	N/A	1548:55:00	underfrequency	18,697	1550:57:00	146
	72.80	N/A	1551:51:00	manual shed	18,697	1959:29:00	18,017
	54.52	N/A	1548:55:00	underfrequency	8,559	2052:11:00	16,534
	56.10	N/A	1548:55:00	underfrequency	12,470	2036:38:00	16,143
	37.40	N/A	1548:55:00	underfrequency	6,720	2027:27:00	10,415
	38.66	N/A	1548:55:00	underfrequency	7,114	2055:10:00	11,839
	65.73	N/A	1548:55:00	underfrequency	8,575	2026:50:00	18,273
	50.65	N/A	1548:56:00	underfrequency	6,111	2106:07:00	16,065
	74.56	N/A	1548:56:00	underfrequency	10,269	1549:39:00	56
	74.56	N/A	1549:42:00	underfrequency	10,269	2019:29:00	20,112
	42.80	N/A	1548:56:00	underfrequency	9,154	1549:40:00	32
	42.80	N/A	1552:20:00	manual shed	9,154	2103:26:00	13,314
	54.10	N/A	1548:56:00	underfrequency	8,773	1653:35:00	3,495
	54.10	N/A	1713:52:00	manual shed	8,773	2010:35:00	9,562
	33.19	N/A	1548:56:00	underfrequency	7,151	2100:29:00	10,337
	62.26	N/A	1548:56:00	underfrequency	10,546	1549:05:00	[illegible]
	62.26	N/A	1555:01:00	manual shed	10,546	2011:28:00	15,[illegible]
	79.06	N/A	1548:56:00	underfrequency	19,003	1631:12:00	3,340
	79.06	N/A	1736:18:00	manual shed	19,003	2001:44:00	11,503
	23.67	N/A	1548:56:00	underfrequency	3,514	1549:23:00	12
	23.67	N/A	1552:20:00	manual shed	3,514	1615:28:00	547
	49.56	N/A	1555:02:00	underfrequency	12,212	1636:12:00	2,037
	52.51	N/A	1557:55:00	underfrequency	13,009	1637:57:00	2,100
	52.51	N/A	1735:44:00	manual shed	13,009	2012:17:00	8,217
	47.99	N/A	1557:54:00	underfrequency	10,872	1600:40:00	132
	48.07	N/A	1557:54:00	underfrequency	11,565	1600:40:00	132
	62.50	N/A	1557:54:00	underfrequency	8,953	1600:41:00	172
	62.50	N/A	1758:04:00	underfrequency	8,953	2000:41:00	7,663
TOTAL	11,302	300			2,892,343		388,017

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Southern Island Appendix 1

MEMBER	FIRM (MW)	INTERRUPTIBLE (MW)	TIME INTERRUPTED	REASON	NUMBER OF CUSTOMERS	TIME RESTORED	MW-MINUTES LOAD LOST
APS	2000	60	1548	underfrequency	300,000	2030	350,000
BURB	100		1548	underfreq. relay	28,948	1744	11600
CFE	249		1549	underfrequency	116,552	by 1713	17,019
		40	1549	underfrequency	1	1615	1,040
	15		1552	underfrequency	10,662	1650	870
	14		1553	underfrequency	9,526	1658	910
	46		1554	underfrequency	14,404	by 1656	2,616
	26		1555	underfrequency	5,606	by 1645	1,288
	5		1602	underfrequency	4,765	by 1659	195
EPE	400	0	1549	underfrequency	150,000	1804	49,580
FARM	13.7		1549:20	underfreqeuncy	4,728	by 1634	5,256
GLEN	103	0	1548	uf load shed	45,100	1746	12154
	19	0	1601	uf load shed	10,660	1626	475
	13	0	1601	manual trip	4,882	1628	351
LDWP	1320			underfrequency	575,000	by 1739	182400
MWD		110	1551	underfrequency		2142	38,610
	103		1551	undervoltage		1557	618
	77		1551	undervoltage		1612	1,617
NEVP	1514		1548	underfrequency	159,000	by 2125	
		30	1548	underfrequency	1	2125	10,110
OXGC	53	53	1549:20	plant trip		1625	2312
PASA	95		HE 1700	underfrequency		1830	
PEGT	12		1548	underfreq. relay		1611	300
	10		1548	underfreq. relay		1613	250
	1		1548	underfreq. relay		1618	30
	16		1548	underfreq. relay		1734	1696
	12		1548	underfreq. relay		1612	288
		1	1548	underfreq. relay	1	1618	30
		11	1548	underfreq. relay	1	1724	1166
		48	1548	underfreq. relay	1	1559	528
PNM			1548	underfrequency	2,300	1608	140
			1604	underfrequency	6,970	1634	360
			1604	underfrequency	19,144	1638	1,734
			1604	underfrequency	6,372	1642	304
			1548	underfrequency	17,657	1630	2,058
			1548	underfrequency	35,848	1634	4,606
			1548	underfrequency	25,727	1645	4,088
			1548	underfrequency	8,812	1709	1,482
			1604	underfrequency	6,144	1723	1,580
			1604	underfrequency	4,990	1733	1,246
			1548	underfrequency	4,753	1734	2,438
			1548	underfrequency	1,111	1750	488
			1604	underfrequency	384	1812	128
			1548	underfrequency	1,360	1832	656
			1548	sensitive loads	N/A	1740	N/A
SCE	4,480		1549	underfrequency	1800000	by 1855	689,023
		56	1830	manual		2100	8,400
	1,483		1606-1612	manual		by 1725	117,301
SDGE	880	N/A	1548	UF load shedding	462,438	1858	93,984
SRP	1700		1548:59	loss of generation	243,000	2140	292,500
TEP	367		1547	underfrequency	96,241	by 1820	32,252
		13	1547	loss of generation	7	2006	3,367
TID	24.2		1548	underfrequency	5,059	1730	4,404
	15.8		1548	underfrequency	3,341	1747	3,144
	16.2		1557	underfrequency	3,570	1756	3,364
TNP		63	1549:52	loss of line	1	1703	4,599
VERN	48		1549	underfrequency	900	1742	5,424
WALC		5	1548:58		1	1819:39:00	755
		20	1549:04	underfrequency	1	1658:09:00	1380
		7	1549:14	underfrequency	1	1621:42:00	224
		2	1549:14	underfrequency	1	1937:24:00	216
		70	1549:14		1	1602:40:00	910
TOTAL	15,231	589			4,195,972		1,975,864

Northern Island

Appendix 1

MEMBER	FIRM (MW)	INTERRUPTIBLE (MW)	TIME INTERRUPTED	REASON	NUMBER OF CUSTOMERS	TIME RESTORED	MW-MINUT. LOAD LOST
BCHA		10	1551	uf load shed	2230	1615	210
BPA	294	147	1548		1	1633	14,098
	80	80	1548		1	1633	7,408
	8	0		?	1		288
	12	0		?	1		432
	24		1550	?	1	1627	864
	4	0		?	1		152
	195	65	1548	voltage relay	1	1635	12,220
COPD	10		1548	undervoltage	1	1648	6,000
DOPD	None	None					
IPC	320	0	1549	blown line fuses, motor contacts dropping out, etc.	3517	1603 to 1822	2,680
MPC	None	None					
PSPL	No Puget load lost. System load was: 2321 MW @ 1500 PAST and 2302 MW @ 1600 PAST.						
SCL	N/A						
SNPD	NA						
SPP	243		1548:53.14	low voltage due to out-of-step swing	non-determinant; possibly as many as 50,000*	customer dependent, from 1 to 45 minutes	4,000 (approximate number)
TCL	41		1548	open tieline	1	2000	10,332
TSGT	27.1		1548	voltage swings	1	1730	2,764
	46.6		1548	voltage swings	100	1604	559
USPN		6	1548	loss of line	1	1724	576
WAUC	20		1548	lost bus		1641	[illegible]
	16		1548	lost bus		1709	[illegible]
WAUM	No interruptions occurred						
PAC	450	0	1548		154,000	1701	32,358
WWPC	No WWP load was interrupted due to this disturbance.						
TOTAL	1790.7	308			209,858		95,075

Alberta Island

Appendix 1

MEMBER	FIRM (MW)	INTERRUPTIBLE (MW)	TIME INTERRUPTED	REASON	NUMBER OF CUSTOMERS	TIME RESTORED	MW-MINUTES LOAD LOST
TAUC		39	1654	underfrequency	1	1703	351
		38	1654	underfrequency	1	1739	1710
		42	1654	underfrequency	1	1800	2772
		83	1649	underfrequency	1	1700	913
	6		1654	underfrequency	1	1658	24
	9		1654	underfrequency	1	1703	81
	96		1654	underfrequency	50,000	1730	3168
	14		1654	underfrequency	1	1700	84
	4		1654	underfrequency	1	1700	24
	17		1654	underfrequency	1	1700	102
	18		1654	underfrequency	6500	1713	266
	7		1654	underfrequency	2500	1722	196
	10		1654	underfrequency	3600	1729	350
	5		1654	underfrequency	1800	1708	70
	3		1654	underfrequency	1080	1656	6
	14		1654	underfrequency	5000	1717	322
	14		1654	underfrequency	5000	1714	280
	16		1654	underfrequency	5700	1720	416
	11		1654	underfrequency	3900	1715	231
	10		1654	underfrequency	3600	1656	20
	95		1654	underfrequency	1	1720	2470
	18		1654	underfrequency	6500	1703	162
	15		1654	underfrequency	5400	1718	360
	25		1654	underfrequency	9000	1704	250
	36		1654	underfrequency	13000	1717	828
		5	1654	underfrequency	1	1730	180
	12		1654	underfrequency	4300	1700	72
	6		1654	underfrequency	2100	1724	180
	200		1654	underfrequency	25000	1730	7200
	100		1654	underfrequency	37913	1712	1800
TOTAL	761	207			191,904		24,888

Appendix 2

Generation Lost

Generation Tripped – August 10, 1996

ISLAND	MEMBER	UNIT NAME	OUTPUT JUST BEFORE DISTURBANCE (MW)	UNIT CAPACITY AT THE TIME (MW)	SPINNING RESERVE (MW)	REACTIVE OUTPUT (MVAR)	REACTIVE CAPABILITY (MVAR)	MW TRIPPED OR RUN BACK	TIME TRIPPED (PAST)	REASON FOR TRIP	TIME/DATE RETURNED TO SERVICE
Alberta	TAUC	A740sGen1(HRM)	87	150	63	-12	70	87	1554:09:00	overspeed	2033
Alberta	TAUC	Cowley Ridge/US Wind	16.5	16.5	0	0	0	16.5	1549	overfrequency	1730
Alberta	TAUC	Dickson Dam	6	6	0	0	0	6	1549	overfrequency	1730
Alberta	TAUC	Drayton Valley Power	10.6	10.6	0	0	0	10.6	1549	overfrequency	1815
Alberta	TAUC	Eagle River Power	21	21	0	0	0	21	1549	overfrequency	1815
Alberta	TAUC	Weldwood	5	5	0	0	0	5	1549	overfrequency	1719
Northern	BCHA	Aberfeldie G1	3	3	0			3	1554	overspeed	1606
Northern	BCHA	McMann G1-2 (IPP)	90	90	0				1554	overspeed	
Northern	BCHA	NWE G1 (IPP)	70	70	0				1554	overspeed	
Northern	BPA	Bonneville F1	10	15	5	0	-4, +4	10	1542	excitation 40TD & 40G	1600
Northern	BPA	Chief Joseph 1	72	83	11	?	-50, +42	72	1549	RAS generation drop	1553
Northern	BPA	Chief Joseph 17	106	110	4	?	-60, +55	106	1549	RAS generation drop	1553
Northern	BPA	Chief Joseph 2	75	83	8	?	-50, +42	75	1549	RAS generation drop	1553
Northern	BPA	Chief Joseph 4	73	83	10	?	-50, +42	73	1549	RAS generation drop	1553
Northern	BPA	Chief Joseph 5	72	83	11	?	-50, +42	72	1549	RAS generation drop	1553
Northern	BPA	Chief Joseph 6	74	83	9	?	-50, +42	74	1549	RAS generation drop	1553
Northern	BPA	Chief Joseph 7	73	83	10	?	-50, +42	73	1549	RAS generation drop	1553
Northern	BPA	Chief Joseph 8	73	83	10	?	-50, +42	73	1549	RAS generation drop	1553
Northern	BPA	Green Peter 1	40	46	6	2	-30, +20	40	1549	overfrequency	1645
Northern	BPA	Lost Creek 1	22	24.5	2.5	2	-5, +10	22	1548 PAST	loss of excitation	1550
Northern	BPA	Lost Creek 2	26	24.5	0	2	-5, +10	26	1548 PAST	loss of excitation	1550
Northern	BPA	McNary 1	66	66	0	38	-50, +20	66	1548 PAST	overspeed/loss of excitation	1618
Northern	BPA	McNary 10	66	80	14	38	-60, +20	66	1548 PAST	overspeed/loss of excitation	1724
Northern	BPA	McNary 11	66	80	14	38	-60, +20	66	1548 PAST	overspeed/loss of excitation	1644
Northern	BPA	McNary 12	66	80	14	38	-60, +20	66	1548 PAST	overspeed/loss of excitation	1647
Northern	BPA	McNary 14	66	80	14	38	-60,+20	66	1548 PAST	overspeed/loss of excitation	1652
Northern	BPA	McNary 2	66	66	0	38	-60, +20	66	1548 PAST	overspeed/loss of excitation	N/A
Northern	BPA	McNary 3	66	66	0	38	-60, +20	66	1548 PAST	overspeed/loss of excitation	1730
Northern	BPA	McNary 4	66	66	0	38	-60, +20	66	1548 PAST	overspeed/loss of excitation	1740
Northern	BPA	McNary 5	66	66	0	38	-60, +20	66	1548 PAST	overspeed/loss of excitation	1635
Northern	BPA	McNary 6	66	66	0	38	-60, +20	66	1548 PAST	overspeed/loss of excitation	1635
Northern	BPA	McNary 7	66	80	14	38	-60, +20	66	1548 PAST	overspeed/loss of excitation	1642
Northern	BPA	McNary 8	66	80	14	38	-60, +20	66	1548 PAST	overspeed/loss of excitation	1639
Northern	BPA	McNary 9	66	80	14	38	-60, +20	66	1548 PAST	overspeed/loss of excitation	1657

Generation Tripped -- August 10, 1996

ISLAND	MEMBER	UNIT NAME	OUTPUT JUST BEFORE DISTURBANCE (MW)	UNIT CAPACITY AT THE TIME (MW)	SPINNING RESERVE (MW)	REACTIVE OUTPUT (MVAR)	REACTIVE CAPABILITY (MVAR)	MW TRIPPED OR RUN BACK	TIME TRIPPED (PAST)	REASON FOR TRIP	TIME/DATE RETURNED TO SERVICE
Northern	EWEB	Smith Creek	0.9					0.9	1549	?	1647
Northern	GCPD	PEC	4	4	0	0	0	4	1548	overfrequency	2125
Northern	GCPD	Wanapum 7	80.5	92	15	24.7	25	80.5	1548	RAS	1554
Northern	GCPD	Wanapum 8	89.6	92	2.4	24.5	25	89.6	1548	RAS	1603
Northern	IPC	CJ Strike Unit #3	29	30	1	10	+15	29	1549:01	field amps	1614
Northern	IPC	Clear Lake	2	2	0	0	1	2	1549		1635
Northern	IPC	Milner #3	1		0	0	0	1	1549	feeder trip	1620
Northern	MPC	Colstrip 1	320	320	0	40 MV	60 MV	320	1548	ATR	1656
Northern	MPC	Colstrip 3	750	750	10	80 MV	200 MV	750	1548	ATR	1707
Northern	MPC	Colstrip 4	750	750	10	100 MV	200 MV	750	1548	ATR	8/11 0329
Northern	PAC	Blundel	22	23	1	n/a	19	22	1548	swing	8/10 1751
Northern	PAC	Boyle	37	80	43	n/a	25	37	1549	transm. loss	8/10 1644
Northern	PAC	COPCO 115	33	65	322	n/a	35	33	1549	transm. loss	8/10 1631
Northern	PAC	Prospect115	37	56	19	n/a	23	37	1549	transm. loss	8/10 1647
Northern	PAC	Swift	207	240	33	n/a	100	207	1547:36	transm. loss	8/10 1650
Northern	PGE	Ogden Martin	10	10	0	0	0	10	1550	unknown	1658
Northern	PGE	Stone Creek	10	10	0		0	10		overexcitation	1551
Northern	SCL	Gen 165	2	2.7	0			2	1549	overvoltage	8/10 2246
Northern	SCL	Gen 166	2	2.7	0			2	1549	overfrequency	8/10 2142
Northern	TCL	EBC 4.6 (SCBID)**	1	1	0	0		1	1548	overfrequency	8/10 2246
Northern	TCL	PEC 66.0 (SCBID)**	1	1	0	0		1	1548	overfrequency	8/10 2142
Northern	TCL	Wynoochee #71	1	12	11	0		1	1548	overfrequency	8/10 1652
Northern	SPP	Verdi Hydro	2.1	2.1	0	0.1		2.1	1548:53	volt. dip or high freq.	8/10 1636:30
Northern	SPP	Stampede, Hydro	0.4	0.4	0	0	non SPPCo	0.4	1548:54	SMP 86 GP relay	8/12 1147:44
Northern	SPP	Washoe #1, Hydro	0.9	0.9	0	0		0.9	1548:55	volt. dip or high freq.	8/10 1728:47
Northern	SPP	Washoe #2, Hydro	0.9	0.9	0	0		0.9	1548:55	volt. dip or high freq.	8/10 1717:19
Northern	SPP	Caithness, Geothermal	9.1	9.1	0	0	IPP	9.1	1548:56	volt. dip	8/10 1636:49
Northern	USPN	Grand Coulee G14	105	113	8	12		105	1548 PAST	generation drop	1732
Northern	USPN	Grand Coulee G15	105	113	8	12		105	1548 PAST	generation drop	1734
Northern	USPN	Grand Coulee G16	105	113	8	12		105	1548 PAST	generation drop	1723
Northern	USPN	Grand Coulee G17	105	113	8	12		105	1548 PAST	generation drop	1735
Northern	USPN	Grand Coulee G18	105	113	8	12		105	1548 PAST	generation drop	1735
Northern	USPN	Grand Coulee G23	750	770	20	50		750	1548 PAST	generation drop	1751
Northern	USPN	Grand Coulee G6	105	113	8	12		105	1548	generation drop	1745
Northern	USPN	Grand Coulee G7	105	113	8	12		105	1548	generation drop	1747
Northern	USPN	Grand Coulee G8	105	113	8	12		105	1548	generation drop	1747
Northern	USPN	Grand Coulee G9	105	113	8	12		105	1548	generation drop	1753
Northern	USPN	Roza	7.3	13.6	6.3	4		7.3	1515 PAST	loss of field	1730
Northern	USPN	Green Springs	6	18	12	0	+5/-5	6	1548	loss of station service	1724
N. Cal.	CDWR	San Luis 7	27	27	0	1	42	27	1548	vibration	1838
N. Cal.	CDWR	Hyatt 1	141	141	0	18	18	141	1555	line trip	8/10 1843
N. Cal.	CDWR	Hyatt 2	132	132	0	17	17	132	1555	line trip	8/10 1843
N. Cal.	CDWR	Hyatt 3	138	141	3	21	21	141	1550	line trip	8/10 1935
N. Cal.	CDWR	Hyatt 4	127	132	5	22	22	132	1550	line trip	8/10 1935
N. C[illegible]	CDWR	Hyatt 5	138	141		22	22	141	1557	line trip	8/10 [illegible]

Generation Tripped – August 10, 1996

ISLAND	MEMBER	UNIT NAME	OUTPUT JUST BEFORE DISTURBANCE (MW)	UNIT CAPACITY AT THE TIME (MW)	SPINNING RESERVE (MW)	REACTIVE OUTPUT (MVAR)	REACTIVE CAPABILITY (MVAR)	MW TRIPPED OR RUN BACK	TIME TRIPPED (PAST)	REASON FOR TRIP	TIME/DATE RETURNED TO SERVICE
N. Cal.	CDWR	Hyatt 6	127	132	5	22	22	132	1557	line trip	8/10 1908
N. Cal.	CDWR	Thermalito 1	26	40	14	4	13	26	1555	line trip	8/10 1848
N. Cal.	CDWR	Thermalito 2	27	35	8	3	13	27	1555	line trip	8/10 1848
N. Cal.	CDWR	Thermalito 3	27	35	8	5	13	27	1555	line trip	8/10 1848
N. Cal.	CDWR	Thermalito 4	27	35	8	3	13	27	1555	line trip	8/10 1848
N. Cal.	CDWR	Thermalito Dam	3	3	0			3	1557	line trip	8/10 1849
N. Cal.	MID	Stone Drop	0.22	0.22	0			0.22	1549:01:00	underfrequency	
N. Cal.	MID	Woodland	32	46.5	14.5	0.5	15	32	1549:01:00	underfrequency	1123
N. Cal.	NCPA	Midway Sunset	11	21	10			264:00:00	1548	line trip	8/10 2333
N. Cal.	PG&E	Contra Costa - 6	340	340	0	121	150	340	1556		8/10 1843
N. Cal.	PG&E	Contra Costa - 7	330	330	0	102	150	330	1556		8/11 0500
N. Cal.	PG&E	Diablo Canyon - 1	1076	1082	6	0	195	1076	1548		8/15
N. Cal.	PG&E	Diablo Cayon - 2	1088	1093	5	0	195	1088	1548		8/16
N. Cal.	PG&E	Hunters Point - 2	10	85	75	4	45	10	1550		8/10 1755
N. Cal.	PG&E	Morro Bay - 1	36	163	127	-24	70	36	1550		8/10 2300
N. Cal.	PG&E	Morro Bay - 2	45	163	118	-20	70	45	1550		8/10 2100
N. Cal.	PG&E	Morro Bay - 3	333	338	5	61	168	333	1550		8/10 2300
N. Cal.	PG&E	Morro Bay - 4	335	338	3	52	168	335	1550		8/11 0200
N. Cal.	PG&E	Moss Landing - 6	738	739	1	170	340	738	1552		8/11 1700
N. Cal.	PG&E	Moss Landing - 7	736	739	3	132	340	736	1552		8/11 0300
N. Cal.	PG&E	Pit 7-1 Hydro	13	56	43	-1	27	13	1552		8/10 1641
N. Cal.	PG&E	Sunset (SCE) - Area QF'S / IPP'S	212	212	0			212			8/10 2200
N. Cal.	PG&E	WASTE TO ENERGY - AREA QF'S / IPP'S	138	138	0			39			
N. Cal.	PG&E	OIL-RECOVERY - AREA QF'S / IPP'S	621	621	0			478			
N. Cal.	PG&E	CO-GENERATION - AREA QF'S / IPP'S	1158	1158	0			582			
N. Cal.	PG&E	Helms 1 Hydro	0	0	0			312			
N. Cal.	SMUD	Camino 1	4	75	71	9.4		4	1549:37:00	antimotor	1617:33
N. Cal.	SMUD	Robbs Peak	10	25	15	1.65		10	1558:01:00	ex overvoltage	1710:53
N. Cal.	SMUD	Union Valley	3	46.7	43.7	0.4		3	1549:40:00	antimotor	1617:16
N. Cal.	WAPA	Folsom						150			
N. Cal.	WAPA	Shasta						100			
Southern	APS	Cholla 1	107	110		-6	37	107	1602:37:600	underfrequency relay	8/10 1759
Southern	APS	Four Corners 5	762	740		-8	248	762	1549:12:510	high furnace pressure	8/11 0222
Southern	APS	Navajo 1	719	750		25	719	719	1548:59:341	SMF filter relay	8/10 2215
Southern	APS	Navajo 2	700	750		7	700	700	1548:59:492	SMF filter relay	8/11 1251
Southern	APS	Navajo 3	704	750		-5	246	704	1549:07:140	main fuel trip	8/12 0608
Southern	APS	Ocotillo GT 2	5	55	50	-2	19	5	1604	underfrequency relay	8/10 1604
Southern	APS	Ocotillo ST 2	110	110		-2	38	110	1601	low drum level	8/10 1722
Southern	APS	Palo Verde 1	1223	1270		156	417	1223	1549:13:315	DNBR reactor trip	8/12 0454
Southern	APS	Palo Verde 3	1270	1270		124	417	1270	1549:13:405	DNBR reactor trip	8/11 1756
Southern	APS	West Phoenix GT 2	20	55	35	3	19	20	1548	underfrequency relay	8/10 1628

Generation Tripped -- August 10, 1996

ISLAND	MEMBER	UNIT NAME	OUTPUT JUST BEFORE DISTURBANCE (MW)	UNIT CAPACITY AT THE TIME (MW)	SPINNING RESERVE (MW)	REACTIVE OUTPUT (MVAR)	REACTIVE CAPABILITY (MVAR)	MW TRIPPED OR RUN BACK	TIME TRIPPED (PAST)	REASON FOR TRIP	TIME/DATE RETURNED TO SERVICE
Southern	CDWR	Alamo 1	10	18	8	0	5	10	1548	line trip	1907
Southern	CDWR	Devil Canyon 1	42	60	18	0	35	42	1548	line trip	1613
Southern	CDWR	Devil Canyon 3	42	80	38	0	37	42	1548	line trip	1613
Southern	CDWR	Devil Canyon 4	42	80	38	0	37	42	1548	line trip	1613
Southern	CDWR	Mojave Siphon 1	8	11	3	0	N/A	8	1548	line trip	1646
Southern	CFE	PJZ-U06	142	155	12	38	60	142	1549	boiler probs.	1700
Southern	EPE	Newman No. 1	56	74	18	7	56	56	1551	static exciter	1922
Southern	EPE	Rio Grande No. 8	108	140	32	11	98	108	1634	high pressure	1829
Southern	FARM	Animas 1	3	3	0			3	1549:20:00	undervoltage	1735
Southern	FARM	Animas 2	3	3	0			3	1549:20:00	undervoltage	1735
Southern	GLEN	Grayson #4	14	44	30	5	20	14	1549	fuel flow	1618
Southern	GLEN	Grayson #5	11	44	33	5	20	11	1550	fuel flow	1618
Southern	LDWP	Haynes 3	140	230	30			140		excitation problems	1803
Southern	LDWP	Intermountain 1	539	539	0			539		SSR relay	1805
Southern	LDWP	Mohave 2	150	150	0			150		coal mill	12-Aug
Southern	LDWP	Scattergood 3	220	220	0			220		UV trip of aux bank	2144
Southern	MWD	Corona	1.9	2.8	-	-	1.5	1.9	1552	underfrequency	8/11
Southern	MWD	Coyote Creek	1	3.1	-	-	1.8	1	1552	underfrequency	8/11
Southern	MWD	Etiwanda	12	23.9	-	-	12	12	1552	undervoltage	2030
Southern	MWD	Foothill 1 & 2	8.6	9.1	-	-	4.8	8.6	1552	underfrequency	2040
Southern	MWD	Lake Mathews	4.5	4.9	-	-	3.3	4.5	1552	undervoltage	2148
Southern	MWD	Perris	4.4	7.9	-	-	-	4.4	1552	undervoltage	8/11
Southern	MWD	Red Mountain	4.5	5.9	-	-	-	4.5	1552	overcurrent	2055
Southern	MWD	San Dimas	8.4	9.9	-	-	-	8.4	1552	undervoltage	2100
Southern	MWD	Sepulveda Canyon	6.2	8.6	-	-	-	6.2	1552	undervoltage	2058
Southern	MWD	Temescal	2.1	2.8	-	-	1.8	2.1	1552	undervoltage	2110
Southern	MWD	Venice	4.4	10.1	-	-	-	4.4	1552	undervoltage	8/11
Southern	MWD	Yorba Linda	4.3	5.1	-	-	-	4.3	1552	overcurrent	8/11
Southern	NEVP	Clark 10	85	85	0	36	60	85	1548	underfrequency	8/10
Southern	NEVP	Clark 5	80	80	0	36	40	80	1548	underfrequency	8/10
Southern	NEVP	Clark 8	80	80	0	36	40	80	1548	underfrequency	8/10
Southern	NEVP	Clark 9	85	85	0	36	60	85	1548	underfrequency	8/10
Southern	NEVP	Mojave 2	111	111	0	n/a		111	1548	underfrequency	8/11
Southern	NEVP	Qualifying Facalities	305	305	0	64	105	305	1548	underfrequency	8/10
Southern	NEVP	Sun Peak 3	70	70	0	35	40	70	1548	underfrequency	8/10
Southern	NEVP	Sun Peak 4	70	70	0	35	40	70	1548	underfrequency	8/10
Southern	OXGC	Oxbow Geothermal	53	53	0	8	30	53	1550:45:00	overspeed	8/10 1625
Southern	SCE	China Lake	93	93	0	-	-	93	1549	underfrequency	1800
Southern	SCE	Delgen	36	36	0	-	-	36	1549	underfrequency	1800
Southern	SCE	Etiwanda 4	318	320	2	-	140	318	1632	low voltage	1810
Southern	SCE	Hillgen	46	46	0	-	-	46	1549	underfrequency	2200
Southern	SCE	Mcgen	91	91	0	-	-	91	1549	underfrequency	1800
Southern	SCE	Mogen	36	36	0	-	-	36	1549	underfrequency	1800
Southern	SCE	Mohave 2	642	790	48	-	350	642	1550	low air	8/12
Sout[illegible]	SCE	Ormond Beach 2	689	750	6[illegible]	-	400	689	1549	overspeed	[illegible]5

Generation Tripped – August 10, 1996

ISLAND	MEMBER	UNIT NAME	OUTPUT JUST BEFORE DISTURBANCE (MW)	UNIT CAPACITY AT THE TIME (MW)	SPINNING RESERVE (MW)	REACTIVE OUTPUT (MVAR)	REACTIVE CAPABILITY (MVAR)	MW TRIPPED OR RUN BACK	TIME TRIPPED (PAST)	REASON FOR TRIP	TIME/DATE RETURNED TO SERVICE
Southern	SCE	Oxbow	50	50	0	-	-	50	1549	underfrequency	1700
Southern	SCE	Pandol	20	20	0	-	-	20	1549	underfrequency	1700
Southern	SCE	Progen	45	45	0	-	-	45	1549	underfrequency	2200
Southern	SCE	Sungen	122	122	0	-	-	122	1549	underfrequency	1700
Southern	SCE	Tengen	38	38	0	-	-	38	1549	underfrequency	2200
Southern	SCE	Westwind-Seawest	3	3	0	-	-	3	1549	underfrequency	1900
Southern	SDGE	Encina 5	205	330	125	99	170	205	1549	low drum level	1636
Southern	SDGE	Encina 4	118	300	182	53	130	118	1549	low drum level	1632
Southern	SDGE	Naval Training Center QF	22	22	0	1	5	22	1550	loss of boiler	1801
Southern	SDGE	Yuma Cogen Assoc. QF	51	51	0	0	0	51	1548	relay malfunction	8/11 0500
Southern	SRP	Agua Fria 3	174	181	7	25	76	174	1549:24:266	gen. backup	1626
Southern	SRP	Coronado 2	357	350	0	28	210	357	1559:03:506	underfrequency	1730
Southern	SRP	Horse Mesa 1	10	10	0	0.5	0.5	10	1548:55:951	undervoltage	1608
Southern	SRP	Mormon Flat 1	10	11	1	0	7.5	10	1549	undervoltage	1707
Southern	SRP	Mormon Flat 2	39	47	8	0	27	39	1549	undervoltage	1704
Southern	SRP	Stewart Mountain	13	13	0	1.9	8	13	1549	overfrequency	1637
Southern	TEP	Irvington 2	30	82	52	0	82	30	1616	boiler upset	1747
Southern	TEP	Springerville 1	332	385	53	93	210	332	1552	operator action	2131
Southern	TEP	Springerville 2	381	385	3	94	210	381	1550	reverse power	8/11 0202
Southern	TID	Hickman PH #1	0.5	0.5	0	0	0	0.5	1557	trouble alarm	1612
Southern	TID	Hickman PH #2	0.5	0.5	0	0	0	0.5	1557	plant	1611
Southern	WALC	Davis Unit No.2	48	51	3	-2	+18, -18	48	15:49:14		1700
Southern	WALC	Hoover N-2	100	130	30	0	+30, -30	100	15:49:14	generator voltage restraint-overcurrent	1615
Southern	WALC	Hoover N-3	100	130	30	12	+30, -30	100	15:49:14	generator voltage restraint-overcurrent	1605
Southern	WALC	Hoover N-8	0 (condensing)	130	130	5	+30, -30	-4	15:49:14	generator voltage restraint-overcurrent	1620
Southern	WAMP	Folsom Unit 1	50	50			63	50	1548:57:00	line trip	1751
Southern	WAMP	Folsom Unit 2	50	50			63	50	1548:57:00	line trip	1751
Southern	WAMP	Folsom Unit 3	50	50			63	50	1548:57:00	line trip	1751
Southern	WAMP	Nimbus Unit 1	7	7				7	1548:57:00	line trip	1800
Southern	WAMP	Stampede Unit 2	0.6	0.65				0.6	1550		
Southern	WAMP	Shasta Unit 2	120	126			73	126	1625	Low gov oil pressure	1954
Southern	WAUC	Glen Canyon 1	102	167	65	10	55	102	1617	loss of bus	1800
Southern	WAUC	Glen Canyon 2	135	167	32	5	45	135	1549	unit dropping	1752
Southern	WAUC	Glen Canyon 4	102	167	65	10	55	102	1617	loss of bus	1735
Southern	WAUC	Glen Canyon 5	135	167	32	5	45	135	1549	unit dropping	1658
Southern	WAUC	Glen Canyon 6	102	167	65	10	55	102	1617	loss of bus	1633
Southern	WAUC	Glen Canyon 7	135	167	32	5	45	135	1549	unit dropping	1652
Southern	WAUC	Glen Canyon 8	135	167	32	5	45	135	1549	unit dropping	
TOTAL								27,269			

Note: Shared units are reported by plant operator and are not included in the data of other participants.

Appendix 3

Transmission Lines Tripped

TRANSMISSION LINES TRIPPED -- AUGUST 10, 1996

MEMBER	LINE NAME	NOMINAL VOLTAGE (KV)	TIME TRIPPED	REASON FOR TRIP	PREDIST-URBANCE SCHEDULE (MW)	PREDIST-URBANCE ACTUAL (MW) AT FIRST-NAMED BUS	REACTIVE FLOW (MVAR) AT FIRST-NAMED BUS	OUT OF SERVICE BEFORE OUTAGE?
Northern California Island								
CDWR	OR-TH-TM #1	230	1555	fire	364	364	50	No
	OR-TM #2	230	1550	ground relay	273	273	43	No
	OR-TH-TM #3	230	1557	fire	273	273	44	No
NCPA	Midway-Sunset	230	1548	disturbance	11			No
PG&E	Round Mountain #2-Malin	500	1548:52:00	voltage collapse		-1355	289	No
	Round Mountain #1-Malin	500	1548:52:00	voltage collapse		-1427	171	No
	Round Moutain-Malin Total			voltage collapse	-2891	-2782		
	Midway-Vincent #1	500	1548:54:00	voltage collapse		510	-29	No
	Midway-Vincent #2	500	1548:54:00	voltage collapse		493	-65	No
	Midwa -Vincent #3	500	1548:54:00	voltage collapse		419	-56	No
	Midway-Vincent				1251			
	Drum-Summit #1	115	1548	out-of-step		6.8	1.2	No
	Drum-Summit #2	115	1548	out-of-step		-1.5	2.5	No
	Spaulding-Summit	60	1548	out-of-step				No
Southern Island								
APS	Four Corners-Pinto	345	1548:54:415	out-of-step	-598	-128	2	
	Navajo-Westwing	500	1548:58:803	out-of-step		683		
	Navajo-Westwing	500	1548:54:825	out-of-step		736		
	Navajo-McCullough	500	1548:58:496	fault	811	709		
	North Gila-Imperial Valley	500	1548:54:576	out-of-step		725	-33	
	Palo Verde-Devers	500	1548:54:639	out-of-step		919	66	
FARM	Glade-Durango	115	1549:20	RAS	0	-28	4.6	No
	Shiprock-Hood Mesa	115	1549:20	RAS	14	4	n/a	No
	Shiprock-Animas	115	1549:20	RAS	39	-1	n/a	No
	Bergin-Gallegos	115	1549:20	RAS		32	2	No
LDWP	Navajo-McCullough	500	1549		628	710		No
	Celilo-Sylmar	+/-500 DC	1549		2757	2350		No
NEVP	Harry Allen-Red Butte	345	1548:49:00	underfrequency	-240	-278	n/a	No
OXGC	Oxbow Geothermal "T-Line"	220	1550:45	plant trip	53	53	9	N/A
PEGT	Springer-Bravo Dome 115-kV	115	1548	underfrequency relay				
PNM	BA-Blackwater	345	1549:04:00	high voltage	20 MW	14	-83	N/A
SCE	Vincent-Westwind-Wilderness	230	1549:00:00	underfrequency	3	3	n/a	No
	Midway-Vincent #1	500	1548:55:00	out-of-step	1251	456	-200	No

TRANSMISSION LINES TRIPPED -- AUGUST 10, 1996

MEMBER	LINE NAME	NOMINAL VOLTAGE (KV)	TIME TRIPPED	REASON FOR TRIP	PREDIST-URBANCE SCHEDULE (MW)	PREDIST-URBANCE ACTUAL (MW) AT FIRST-NAMED BUS	REACTIVE FLOW (MVAR) AT FIRST-NAMED BUS	OUT OF SERVICE BEFORE OUTAGE?
	Midway-Vincent #2	500	1548:55:00	out-of-step		457	-110	No
	Midway-Vincent #3	500	1548:35:00	out-of-step		373	-140	No
	Palo Verde-Devers	500	1548:55:00	out-of-step	263	905	-11	No
	Control-Silver Peak #A	55	1550:00:00	out-of-step	6.5	6.5	n/a	No
	Control-Silver Peak #B	55	1550:00:00	out-of-step	6.5	6.5	n/a	No
SDGE	North Gila-Imperial Valley	500	1548	out-of-step	900	757	-10	No
SRP	Brandow-Ward	230	1549:08:00	misoperation	n/a	136	0	No
TNP	Hidalgo-Playas	115	1548:00:00	underfrequency	27	27.2	7.9	No
	MD #1-Ivanhoe	115	1549:52:00	underfrequency	63	63.3	8.9	No
WALC	Pinnacle Peak-Flagstaff #1	345	1549:48	xfrmr overexcitation	424	442		No
	Pinnacle Peak-Flagstaff #2	345	1549:48	xfrmr overexcitation	425	443		No
WAMP	Folsom-Roseville	230	1548:57:00	overvoltage				No
WAUC	Hesperus-Waterflow	345	15:48:54.936	out-of-step	625	500		No
	Shiprock-Lost Canyon	230	15:48:54.703	out-of-step				No
	Glade Tap-Durango	115	15:48:54.938	out-of-step				No
	Glen Canyon-Sigurd	230	15:48:53.708	out-of-step	33	151		No
	Glen Canyon-Flagstaff #1 and #2	345	15:49:45.271	xfrmr overexcitation	849	894		No
Northern Island								
BCHA	5L94 (CBK-LGN)	525	1554	undervoltage	300	300		
	786L (NTL-Coleman)	138	1554	overcurrent	35	35	?	
	777L (NTL-LLC)	138	1554	overcurrent	35	35	?	
	5L31 (MSA-DMR)	525	1549	overvoltage	147	147	-40	
BPA	Big Eddy-Ostrander 1	500	8/10 1406	tree:tree		-89	-130	Yes
	John Day-Marion 1	500	8/10 1452	unknown:unknown		248	-207	Yes
	Marion-Lane 1	500	8/10 1452	power system condition: forced (configuration)		331	-105	Yes
	Keeler-Allston 1	500	8/10 1542	tree:tree		1298	-113	Yes
	Pearl-Keeler 1	500	8/10 1542	power system condition: forced (configuration)		-1399	268	Yes
	Ross-Lexington 1	230	8/10 1547	tree:tree growth		-332	69.2	Yes

TRANSMISSION LINES TRIPPED -- AUGUST 10, 1996

MEMBER	LINE NAME	NOMINAL VOLTAGE (KV)	TIME TRIPPED	REASON FOR TRIP	PREDIST-URBANCE SCHEDULE (MW)	PREDIST-URBANCE ACTUAL (MW) AT FIRST-NAMED BUS	REACTIVE FLOW (MVAR) AT FIRST-NAMED BUS	OUT OF SERVICE BEFORE OUTAGE?
	Buckley-Grizzly 1	500	8/10 1548	power system condition: instability - zone 1		1515	-167	No
	Chief Joseph PH-Chief Joseph Sub 1	230	8/10 1548	power system condition: RAS initiated		-212	18	No
	Chief Joseph PH-Chief Joseph Sub 2	230	8/10 1548	power system condition: RAS initiated		-283	39	No
	Chief Joseph PH-Chief Joseph Sub 5	500	8/10 1548	power system condition: RAS initiated		-409	99	No
	Captain Jack-Malin 1	500	8/10 1548	power system condition: instability		97.1	90.1	No
	Captain Jack-Malin 2 (PacifiCorp)	500	8/10 1548	power system condition: instability		95.8	76.9	No
	Captain Jack-Meridian 1 (PACW)	500	8/10 1548	power system condition: instability (SFT - underimpedance)		-530	-2.7	No
	Grizzly-Captain Jack 1	500	8/10 1548	power system condition: instability		1313	-239	No
	Grizzly-Malin 2 (PG&E)	500	8/10 1548	power system condition: instability		1278	-236	No
	Grizzly-Round Butte 1 (PG&E)	500	8/10 1548	power system condition: instability		-3	26	No
	Grizzly-Ponderosa Section of Grizzly-Summer Lake 1	500	8/10 1548	power system condition: instability		1028	-210	No
	John Day-Grizzly 1	500	8/10 1548	power system condition: instability		1060	-179	No
	John Day-Grizzly 2	500	8/10 1548	power system condition: instability		1048	-166	No

TRANSMISSION LINES TRIPPED -- AUGUST 10, 1996

MEMBER	LINE NAME	NOMINAL VOLTAGE (KV)	TIME TRIPPED	REASON FOR TRIP	PREDISTURBANCE SCHEDULE (MW)	PREDISTURBANCE ACTUAL (MW) AT FIRST-NAMED BUS	REACTIVE FLOW (MVAR) AT FIRST-NAMED BUS	OUT OF SERVICE BEFORE OUTAGE?
	Captain Jack-Olinda 1 (WAPA)	500	8/10 1548	power system condition: instability	SW-AC Schedule Combined Captain Jack-Olinda and Malin-Round Mountain 1 and 2 = 4285	1647	-262	No
	Malin- Round Mountain 1 (WAPA)	500	8/10 1548	power system condition: instability (SFT-underimpedance)	SW-AC Schedule Combined Captain Jack-Olinda and Malin-Round Mountain 1 and 2 = 4285	1350	-181	No
	Malin-Round Mountain 2 (PACW)	500	8/10 1548	power system condition: instability (SFT-underimpedance)	SW-AC Schedule Combined Captain Jack-Olinda and Malin-Round Mountain 1 and 2 = 4285	1435	-224	No
	Summer Lake-Midpoint 1 (PACW)	500	8/10 1548	power system condition: instability		-569	272	No
	Warner-Pacific P+L CO 1 (Bank Reading)	115	8/10 1548	unknown:unknown		20.9	-5	No
	Ponderosa-Grizzly	500/230	8/10 1548	power system condition: instability		77.5	-4	No
	Ponderosa-Summer Lake Section of Grizzly-Summer Lake 1	500	8/10 1548	miscellaneous: line material failure		944	-22	No
	Summer Lake-Malin 1 (PACW)	500	8/10 1548	power system condition: instability		1510	-299	No
	Converter 1 Tap of Celilo-Sylmar PL 3	1000	8/10 1548	power system condition: forced (configuration)	HVDC Power Order at Celilo = 2848 MW	2851	77.6	No
	Valve Group 1 Tap of Celilo-Sylmar PL 3	1000	8/10 1548	power system condition: forced (configuration)				No

TRANSMISSION LINES TRIPPED -- AUGUST 10, 1996

MEMBER	LINE NAME	NOMINAL VOLTAGE (KV)	TIME TRIPPED	REASON FOR TRIP	PREDIST-URBANCE SCHEDULE (MW)	PREDIST-URBANCE ACTUAL (MW) AT FIRST-NAMED BUS	REACTIVE FLOW (MVAR) AT FIRST-NAMED BUS	OUT OF SERVICE BEFORE OUTAGE?
	Valve Group 7 Tap of Celilo-Sylmar PL 3	1000	8/10 1548	power system condition: forced (configuration)				No
	La Pine-Chilquin 1 (PACW)	230	8/10 1550	power system condition: forced (configuration) - via KFalls trip		72.6	-19.8	No
	La Pine-Fort Rock 1	115	8/10 1550	power system condition: forced (configuration)		11.1	-5.1	No
	La Pine 1-Midstate E Coop	115	8/10 1550	power system condition: forced (configuration)		23.9	1.8	No
	Redmond 1 -Prineville (PP&L)	115	8/10 1550	zone 3 - three phase		29.5	0.7	No
	Redmond 1-Pilot Butte (PP&L)	230	8/10 1550	CBTT		131.7	4.8	No
	La Pine 1-Pilot Butte E (PACW)	230	8/10 1550	power system condition: forced (configuration)		-108	22.5	No
	Valve Group 2 Tap of Celilo-Sylmar PL 4	1000	8/10 1604	power system condition: forced (configuration)				No
	Valve Group 8 Tap of Celilo-Sylmar PL 4	1000	8/10 1606	power system condition: forced (configuration)				No
	Converter 2 Tap of Celilo-Sylmar PL 4	1000	8/10 1607	power system condition: forced (configuration)	HVDC Power Order at Sylmar = 1223 MW	1373 MW at Celilo	142 4 MW at Celilo	No
	Valve Group 2 Tap of Celilo-Sylmar PL 4	1000	8/10 1608	power system condition: forced (configuration)				No
	Valve Group 6 Tap of Celilo-Sylmar PL 4	1000	8/10 1609	power system condition: forced (configuration)				No

TRANSMISSION LINES TRIPPED -- AUGUST 10, 1996

MEMBER	LINE NAME	NOMINAL VOLTAGE (KV)	TIME TRIPPED	REASON FOR TRIP	PREDIST-URBANCE SCHEDULE (MW)	PREDIST-URBANCE ACTUAL (MW) AT FIRST-NAMED BUS	REACTIVE FLOW (MVAR) AT FIRST-NAMED BUS	OUT OF SERVICE BEFORE OUTAGE?
	Valve Group 3 Tap of Celilo-Sylmar PL 3	1000	8/10 1610	power system condition: forced (configuration)				No
	Valve Group 4 Tap of Celilo-Sylmar PL 4	1000	8/10 1610	power system condition: forced (configuration)				No
	Valve Group 5 Tap of Celilo-Sylmar PL 3	1000	8/10 1610	power system condition: forced (configuration)				No
IPC	Midpoint-Summer Lake	500	1548:53.412	transfer trip from Summer Lake		628	-240	No
SPP	North Truckee-Summit (#133 line)	120	1548:55	out-of-step		-10.4	-3.5	No
	California-Summit (#102 line)	120	1548:55	out-of-step		2.6	-4.9	No
	Truckee-Tahoe Donner (#607 line)	60	1548:55	out-of-step related		-5.3	-1.4	No
	Silver Peak-Control (#501 line)	55	1548:56	out-of-step related		4.8	-2.6	No
	Silver Peak-Control (#502 line)	55	1548:56	out-of-step related		8.3	-2.2	No
TSGT	Hesperus-Waterflow, at Hesperus	345	1548:54.934	out-of-step				No
	Hesperus-Montrose, both ends	345	1548:54.962	zone 1				No
	Montrose-Nucla at Montrose	115	1549:49	TT RAS from Montrose				No
	Lost Canyon-Shiprock at Lost Canyon	230	1549:50	out-of-step				No
	Lost Canyon-CO2 at Lost Canyon	115	1549:56	zone 1				No
USPN	Green Springs/Lone Pine	69	1548 PAST	N/A	6	6	0	No
TAUC	1201L-TransAlta to BCHydro	500	1654	undervoltage	-360	-344	-150	No
	Natal-TransAlta 138-kV Tie	138	1654	overcurrent	-60	-60	-10	No
	9L913L/913L-Sundance to Mitsue	240	1659	RAS overvoltage	n/a	209	-60	No

Appendix 4

Abnormal Conditions

Northern California Island

ABNORMAL SYSTEM CONDITIONS

1. Abnormal system conditions that may have contributed to the occurrence or impact of the disturbance, especially reactive devices that were out of service or limited in response capability.

	Abnormal Conditions
NCPA	None
PG&E	Vaca-Dixon-Tesla 500-kV line series capacitor bank segment #2 at Vaca-Dixon O/S Los Banos-Midway #1 500-kV line series capacitor bank segment #1 at Los Banos O/S Midway-Vincent #1 500-kV line series capacitor bank segment #1 at Midway O/S Midway-Vincent #3 500-kV line series capacitor bank segment #1 at Midway O/S
SMUD	None

2. Abnormal system conditions that adversely impacted system restoration.

	Abnormal Conditions
NCPA	None
PG&E	None
SMUD	None

Southern Island

ABNORMAL SYSTEM CONDITIONS

1. Abnormal system conditions that may have contributed to the occurrence or impact of the disturbance, especially reactive devices that were out of service or limited in response capability.

	Abnormal Conditions
APS	None
BURB	None
EPE	None
GLEN	None
OXGC	None
PNM	None
SDGE	SDG&E's electric system was operating normally prior to the disturbance
TNP	Normal
WALC	None

2. Abnormal system conditions that adversely impacted system restoration.

	Abnormal Conditions
APS	ECC building UPS failed EMS down from 1548 to 1652
BURB	Frequency decay 60 Hz to 58.55 Hz Frequency remained below 59 Hz for 20 minutes.
EPE	None
GLEN	None
NEVP	The phase angle was swinging on the Harry Allen line and would not allow us to close back with Utah until LDWP closed the Navajo-McCullough line
OXGC	None
PASA	System unstable for approximately one hour and could not restore load.
PNM	Breaker and control problems prevented normal automatic restoration after frequency recovered 3,258 additional MW/min. of outage time and 17,369 customers affected by these problems
SDGE	None
SRP	Loss of 10 RTUs at distribution substations, loss of the EMS three times, slow EMS response time
TNP	Loss of EMS computers at 1556:18; apparently due to alarm management problem. This limited response to manual controls
WALC	*Not applicable*

Northern Island

Appendix 4

ABNORMAL SYSTEM CONDITIONS

1. Abnormal system conditions that may have contributed to the occurrence or impact of the disturbance, especially reactive devices that were out of service or limited in response capability.

Abnormal Conditions

BCHA	**Reactive equipment out of service for maintenance** Burrard G2 automatic voltage regulator (+140/-90 MVAR) ING 2RX2 on forced outage (-125 MVAR) GM Shrum 500-kV line shunt reactor (-122 MVAR) Williston 500-kV line shunt reactor (-122 MVAR) **Reactive equipment out of service (but available for manual switching) for voltage support during high exports** Kelly Lake, two 500-kV shunt reactors (-122 MVAR each) Nicola, two 500-kV shunt reactors (-122 MVAR each) Ashton Cr, on e 500-kV shunt reactor (-122 MVAR) MDN (auto-var off), 230-kV shunt reactor (-200 MVAR)
CSU	CW and CY cap banks off line for repair, 102.5 MVAR
DOPD	None
IPC	Brady S012 synchronous condenser out of service for control rebuild (+72 to -31 MVAr) Copperfield (Oxbow-Lolo line) series capacitors out. Brownlee Unit #4 off for annual maintenance (100 MVA) Lower Salmon Unit #1 off for installation of automation equipment (21 MVA) Hunt shunt capacitor C131 out to repair lightning damage to air break switch (54 MVAr) CJ Strike Unit #1 off for maintenance (30 MVA)
MPC	MPC system was normal
PSPL	**Transmission lines out of service before system event:** Shuffleton-Lakeside 115-kV out of service for road work relocation Fairwood-Cedar Falls 115-kV out of service for maintenance Whidbey-Greenbank #2 115-kV out of service for road work relocation Bremerton-BPA Kitsap (Navy line) 115-kV out of service due to Nave work Sedro Woolley tap-BPA Monroe/Snohomish 230-kV out for line rebuild
SCL	None
SNPD	None
TCL	None
TSGT	None
WALM	SCADA failed at time of initial spike. Restored SCADA at 1644. No breakers in abnormal position.
WAUM	None
WWPC	None

2. Abnormal system conditions that adversely impacted system restoration.

Abnormal Conditions

BCHA	LGN S 3522 CB failed to close to synch with CBK on 5L94 at 1623. Second try at 1629 successfully tied TAUC to BCHA
DOPD	None
EWEB	Alarms overloaded the EMCS to the point it became dysfunctional. Generators esperienced wide swings in MW and MVR before stabilizing
PSPL	**Comments from Dispatcher on shift during system event:** #1 Poor communication between companies!!! Didn't find out the North-South ties had tripped for sure for about one hour. Key contacts didn't communicate because, they didn't know they should , didn't have the time, or called the wrong companies. #2 Someone took control of the Mid-Columbia generation which would not allow AGC to work. Generation could not be lowered manually even by the dispatchers in charge of the plants. #3 After running schedules for 45 minutes some companies declared the schedule 0 (zero) for all hour. This is not real time operation and doesn't reflect the true state of the system. Example: If at 1745 PAST a 300 MW schedule is cut it should show 225 MW for the hour not 0 (zero). Companies in the middle of a market transaction did not need to be called at first. In and out wheeling can be adjusted after the fact since it is just an accounting function and doesn't effect generation/deviation. #4 The sheer number of schedules makes orderly emergency response intolerable. The company in the middle of energy transfers got notified and was expected to call the energy provider when it is not that company's responsibility.
SNPD	Nothing to report
TSGT	None
WAUM	None
WWPC	None

Alberta Island

Appendix 4

ABNORMAL SYSTEM CONDITIONS

1. Abnormal system conditions that may have contributed to the occurrence or impact of the disturbance, especially reactive devices that were out of service or limited in response capability.

	Abnormal Conditions
TAUC	None

2. Abnormal system conditions that adversely impacted system restoration.

	Abnormal Conditions
TAUC	None

Appendix 5

Sequence of Events

AUGUST 10, 1996 WSCC DISTURBANCE--SEQUENCE OF EVENTS

EVENT #	MEMBER	TIME (PAST)	EVENT	RESTORED
0			REVISED 9/5/96----0900	
1			**PREDISTURBANCE EVENTS**	
1	BPA	**14:01:29.829**	**500-KV BIG EDDY-OSTRANDER 1LG FAULT, RELAYED SP, UNSUCCESSFUL RECLOSE; 3 POLE TRIP; TREE IN LINE**	
2	PGE	14:01:29.879	230-KV MCLOUGLIN-BIG EDDY TRIP AT MCLOUGLIN ONLY; MCLOUGLIN TRIPS ONLY 3 CYC. AFTER OSTRANDER; RELAY MISCOORDINATION--FIXED	1401
3	BPA	14:03:35.878	LINE CLOSED AT BIG EDDY, LOAD PICKED UP	
4	BPA	**14:06:33.528**	**500-KV BIG EDDY-OSTRANDER 1LG FAULT, RELAYED SP, RECLOSE**	
5	PGE	14:06:33.578	230-KV MCLOUGLIN-BIG EDDY TRIP AT MCLOUGLIN ONLY; MCLOUGLIN TRIPS ONLY 3 CYC. AFTER OSTRANDER; RELAY MISCOORDINATION--FIXED	1406
6	BPA	14:06:35	KEELER SVC ALARM	
7	BPA	**14:06:39.769**	**500-KV BIG EDDY-OSTRANDER 1LG FAULT, RELAYED 3 POLE TRIP**	
8	BPA	14:13:08.370	GRIZZLY REACTOR 3 OPEN	
9	BPA	**14:52:37.156**	**500-KV JOHN DAY-MARION 1LG FAULT; TRIPS TO LOCKOUT; FORCES OPEN MARION-LANE AT MARION DUE TO PCB OUT OF SERVICE AT MARION, TREE IN LINE**	
10	BPA	14:52:37.271	CHIEF JOE BRAKE LBD A-425 OPERATE BY RELAY	
11	BPA	14:56:43.953	JOHN DAY-MARION MANUAL TEST FROM JOHN DAY--BAD	John Day Marion @ 2250, Marion Lane @ 2256
12	BPA	06:44.2	CAPTAIN JACK-OLINDA LINE FAULT DETECTOR PU--UNKNOWN CAUSE; REPEATS AT 15:27, 15:32	
13			**BEGINNING OF DISTURBANCE**	
13	BPA	**15:42:03.139**	**500-KV KEELER-ALLSTON 1LG FAULT; TRIPPED SINGLE POLE WITH UNSUCCESSFUL RECLOSE; FORCES OPEN KEELER-PEARL AT KEELER; 500/230 KEELER TRANSFORMER OPEN FOR MAINTENANCE. UNSUCCESSFUL TEST AT 15:44:01.292, TREE IN LINE**	**Both lines @ 20:57**
14	BPA	15:42:37	ECC REPORTS COLUMBIA BASIN VOLTAGE LOW	
15	PGE	15:45	PGE REPORTS THEIR 230 SYSTEM AROUND RIVERGATE IS OVERLOADED	
16	USPN	15:47	GRAND COULEE SCADA FAILURE -- 2 HOURS	
17	PG&E	15:47	PIT #1 P.H. #1 UNIT RELAYED	1651
18	PAC	15:47:29	MERWIN-ST. JOHNS 115-KV LINE RELAYS -- KD ZONE 1 MALFUNCTION (Note: time based on backup SCADA system -- may be several seconds off)	
19	BPA	**15:47:36**	**230-KV FAULT ON ROSS-LEXINGTON LINE; DROPS PACIFICORP GENERATION FROM MERWIN, SWIFT; TREE IN LINE, FAULT STARTED SMALL FIRE**	**Line @ 16:26**
20	BPA	**15:47:36**	**MCNARY TRIPS 117 MW (2 UNITS)**	
21	BPA	**15:47:40**	**MCNARY TRIPS 215 MW (3 UNITS)**	
22	BPA	**15:47:44**	**MCNARY TRIPS 75 MW (1 UNIT)**	
23	BPA	**15:47:52**	**MCNARY TRIP (1 UNIT)**	
24	PG&E	15:47:52	SYSTEM FREQUENCY 59.75 HZ, PG&E DROPS E-20 CUSTOMERS	
25	PG&E	15:47:55	SYSTEM FREQUENCY 59.3 TO 58.7 HZ, PG&E DROPS UNDERFREQUENCY LOAD BLOCKS 1 THROUGH 6	
26	BPA	15:48	NORTHERN ISLAND LOAD LOST -- 422 MW FIRM/227 INT, 6 CUSTOMERS	1633
27	USPN	15:48	GRAND COULEE G14 - G18 TRIP -- 525 MW GEN DROP	1732 PAST
28	USPN	15:48	GRAND COULEE G23 -- 750 MW GEN DROP	1751 PAST
29	USPN	15:48	GRAND COULEE G6 - G9 TRIP -- 420 MW GEN DROP	1745 PAST
30	USPN	15:48	GREEN SPRINGS 6 MW LOSS OF STATION SERVICE	1724 PAST

EVENT #	MEMBER	TIME (PAST)	EVENT	RESTORED
31	USPN	15:48	GREEN SPRINGS/LONE PINE 69-KV LINE TRIP	
32	USPN	15:48	ROZA PH TRIP 7.3 MW LOSS OF FIELD	1730 PAST
33	EPE	15:48	SOUTHERN ISLAND LOAD LOST – 400 MW;150,000 CUSTOMERS	1704
34	IPCO	15:48	NORTHERN ISLAND LOAD LOST – 320 MW; 3,517 CUSTOMERS	1822
35	LDWP	15:48	LOAD SHED – 1320 MW @ 58.5	1739
36	LDWP	15:48	SOUTHERN ISLAND LOAD LOST – 1328 MW; 513,700 CUSTOMERS	1738
37	PAC	15:48	NORTHERN ISLAND LOAD LOST – 450 MW, 154,000 CUSTOMERS	1701
38	PG&E	**15:48**	**CAPTAIN JACK-OLINDA 500-KV LINE RELAYED**	
39	PG&E	**15:48:54.7**	**DRUM-SUMMIT #1 -115-KV LINE TRIPPED**	**1915**
40	PG&E	**15:48:54.7**	**DRUM-SUMMIT #2 -115-KV LINE TRIPPED (NORTHERN CALIFORNIA SEPARATED FROM NORTHERN NEVADA)**	**1915**
41	PG&E	15:48	N. CALIFORNIA LOAD LOST – 21,705 MW FIRM; 600 INT; 494,128 CUSTOMERS	2042
42	PSNM	15:48	SOUTHERN ISLAND LOAD LOST – 480 MW; 141,572 CUSTOMERS	1832
43	SDGE	15:48	SOUTHERN ISLAND LOAD LOST – 521 MW; 286,212 CUSTOMERS	1858
44	SDGE	15:48	YUMA CO-GEN ASSOCIATION QF TRIPPED WHILE CARRYING 51 MW OF LOAD	
45	SMUD	15:48	N. CALIFORNIA ISLAND LOAD LOST – 1,530 MW; 295,185 CUSTOMERS	2103
46	TAUC	15:48	320PGEN1(KH1) TRIP 200 MW RUNBACK MW	
47	TAUC	15:48	ALBERTA ISLAND LOAD LOST – 761 MW FIRM;207 MW INT; 191,904 CUSTOMERS	1700
48	TSGT	15:48	73.1 LOAD SHED–VOLTAGE SWING	
49	TSGT	15:48	NORTHERN ISLAND LOAD LOST – 73 MW; 101 CUSTOMERS	1730
50	USLC	**15:48**	**DAVIS UNIT # 1 - # 5 TRIP 240 MW**	
51	USLC	**15:48**	**HOOVER N-8 TRIP -- 4 MW; TRIP BY GEN VOLTAGE RESTRAIN OC**	**1620**
52	USLC	**15:48**	**HOOVER UNITS A2 - A9 TRIP 821 MW**	
53	USLC	**15:48**	**HOOVER UNITS N1, N4-N7 TRIP 130 MW**	
54	USLC	**15:48**	**HOOVER UNITS N2, N3 TRIP 200 MW; TRIP BY GEN VOLTAGE RESTRAIN OC**	**1615**
55	USLC	**15:48**	**PARKER UNIT NO.1 - 4 TRIP 88 MW**	
56	WAUC	15:48	CURECANTI (NORTH) FREQUENCY TO 61.15 HZ AND RETURNED TO 60.45 HZ -- TIME??	
57	WAUC	15:48	GLEN CANYON (SOUTH) FREQUENCY TO 59.78 HZ -- TIME??	
58	WAUC	**15:48**	**MONTROSE 115-KV BREAKER 571 (NUCLA) TRIPPED VIA RAS**	
59	WAUC	**15:48**	**TRI-STATE G&T NUCLA UNITS 1, 2, 3, AND 4 RELAYED WHILE CARRYING 100 MW**	
60	BPA	**15:48:09**	**MCNARY TRIP (1 UNIT)**	
61	BPA	15:48:21.659	MALIN 500-KV SHUNT CAP GROUP 3 PCB 4182 AUTOMATIC VOLTAGE CLOSE	
62	SDGE	15:48:22	NORTH GILA-IMPERIAL VALLEY 500-KV LINE RELAYED	1827
63	SDGE	15:48:30	GAS TURBINE UNDERFREQUENCY START	
64	SDGE	15:48:32	UNDERFREQUENCY LOAD SHEDDING BEGINS	
65	BPA	15:48:48.618	MALIN POWER RATE RELAY EXPORT TRANSMIT RAS-ACDITT (MUNR AT .677)	
66	BPA	15:48:48.812	CAPTAIN JACK POWER RATE RELAY EXPORT TRANSMIT	
67	NEVP	**15:48:49**	**HARRY ALLEN-RED BUTTE 345-KV LINE TRIP -- OUT-OF-STEP**	18:54:01
68	GPUD	15:48:50	WANAPUM W7,8 TRIP BY RAS	
69	BPA	15:48:51.814	CELILO DC RAS A 10 SEC SLIDING WINDOW ALGORITHIM LEVEL 2	
70	BPA	15:48:52	TOGGLING VOLTAGE ALARMS ALL OVER BPA SYSTEM	
71	PG&E	15:48:52.240	TABLE MT. MSC #5 CLOSED BREAKER 672 SUCCESSFULLY. TABLE MT. BUS VOLTAGE WAS APPROXIMATELY 430 KV (525 NOMINAL)	
72	BPA	15:48:52.288	CELILO DC-RASB 10 SEC SLIDING WINDOW ALGORITHIM LEVEL 1	
73	BPA	15:48:52.375	CELILO DC RAS TRANSMITS (MALIN CAP, FORTROCK, TEB, SANFRAN)	
74	BPA	15:48:52.472	500-KV MALIN SHUNT CAP GRP 4 INSERTED BY CELILO RAS	

EVENT #	MEMBER	TIME (PAST)	EVENT	RESTORED
75	BPA	15:48:52.487	500-KV FORT ROCK SERIES CAPS INSERTED BY CELILO RAS--GRIZZLY-CAPTAIN JACK; GRIZZLY-MALIN; GRIZZLY-SUMMER LAKE; ALL IN AT 15:48:52.520	
76	BPA	15:48:52.549	BUCKLEY OUTPUTS GRIZZLY LINE TRIP 3-PHASE (WITHIN ZONE 3)?	
77	BPA	15:48:52.558	DITTMER RECEIVES LOS BANOS POWER RATE RELAY SIGNAL (SENSITIVE)	
78	BPA	15:48:52.563	CELILO DC-RASB 10 SEC SLIDING WINDOW ALGORITHIM LEVEL 1	
79	SCE	15:48:52.570	FOUR CORNERS EASTERN RAS SEP. SIGNAL RECV	
80	BPA	15:48:52.571	MALIN-RDMT 2 SWITCH-INTO-FAULT OPERATES (UNDERIMPEDANCE) 315 KV	
81	BPA	15:48:52.587	MALIN-RDMT 1 SWITCH-INTO-FAULT OPERATES (UNDERIMPEDANCE)	
82	BPA	15:48:52.588	BUCKLEY-GRIZZLY LINE OPEN AT BUCKLEY; OPEN @ GRIZZLY @ 52.598	17:04
83	BPA	15:48:52.613	MALIN-ROUND MOUNTAIN 2 LINE OPEN AT MALIN (LINE INSULATOR FLASHES OVER AFTER LINE IS OPENED. MALIN VOLTAGE PRIOR TO TRIP APPROX. 170 KV PHASE/GROUND. INSULATOR FAULT STARTED FIRE (.56PU)	Restored 8/11/96 @ 07:08
84	BPA	15:48:52.618	JOHN DAY-GRIZZLY NO. 1 OPEN AT JOHN DAY; OPEN AT GRIZZLY AT 52.633	15:52
85	BPA	15:48:52.627	RAS-ACA DYNAMIC BRAKE ALGORITHIM OPERATE	
86	BPA	15:48:52.632	MALIN-ROUND MOUNTAIN 1 LINE OPEN AT MALIN	18:29
87	BPA	15:48:52.641	JOHN DAY-GRIZZLY NO. 2 OPEN AT GRIZZLY; OPEN AT JOHN DAY AT 52.654	16:13
88	BPA	15:48:52.643	CHIEFJOE BRAKE INSERT A595	
89	BPA	15:48:52.660	CHIEFJOE PH 5 OPEN	16:28
90	PAC	15:48:52.682	CAPTAIN JACK-MERIDIAN OPEN AT CAPTAIN JACK (PCB 4983,4986), RECLOSE BLOCKED	17:02
91	SCE	15:48:52.700	SCE VINCENT VOLTAGE STARTS DOWN	
92	BPA	15:48:52.706	GRAND COULEE AGC BLOCKED BY RAS	
93	BPA	15:48:52.725	GRAND COULEE 500-KV PCB 2392, 2396 TRIP (PH G23)	
94	BPA	15:48:52.727	CHIEF JOE PH LINE 1 (PCB A576) TRIP	15:57
95	BPA	15:48:52.727	CHIEF JOE PH LINE 2 (PCB A580) TRIP (SENT AT .685?)	15:56
96	BPA	15:48:52.735	CHIEF JOE PCB 4588 OPEN VIA RELAY	16:28
97	BPA	15:48:52.735	RAS-ACA INTERTIE SEPARATION ALGORITHIM, BRAKE, HIGH GEN DROP OPERATE (RESET .753)	
98	SCE	15:48:52.735	RAS-ACA FOUR CORNERS SIGNAL SENT (SCE RECEIVED AT 52.82)	
99	PGE	15:48:52.740	GRIZZLY-MALIN NO.2 OPEN AT GRIZZLY (PCB 4048); OPEN AT MALIN @ 52.750	16:08
100	BPA	15:48:52.743	CHIEF JOE BRAKE LBD A-425 OPERATE BY RELAY	
101	WAMP	15:48:52.744	OLINDA RECEIVES BPA RAS LLL	
102	APS	15:48:52.757	FOUR CORNERS RAS SIGNAL RECEIVED	
103	WAMP	15:48:52.767	OLINDA TERMINAL, CAPTAIN JACK OPEN VIA RAS (COI NOW OPEN BETWEEN OREGON AND CALIFORNIA)	
104	BPA	15:48:52.771	RAS-ACA, BRAKE, HIGH GEN DROP ALGORITHIM OPERATE	
105	PAC	15:48:52.778	CAPTAIN JACK-GRIZZLY LINE OPEN AT CAPTAIN JACK (PCB 4993,4990); OPEN AT GRIZZLY AT 52.794	17:01
106	BPA	15:48:52.782	CAPTAIN JACK-OLINDA LINE OPEN AT CAPTAIN JACK (PCB 4977,4980)	18:18
107	BPA	15:48:52.788	MALIN SOUTH BUS LOR TRIP (PACW TX HIGH VOLTAGE?)--OPENS 500/230 TRANSFORMER	
108	BPA	15:48:52.793	MALIN SOUTH BUS DIFFERENTIAL	
109	SCE	15:48:52.800	ELDORADO PACI RAS SEND TRIP TO FOUR CORNERS	
110	SCE	15:48:52.800	SCE RECEIVED PACI 4 CORNER SEPARATION SIGNAL	
111	BPA	15:48:52.805	CHIEF JOE GEN SIGNAL DROP RECEIVED	
112	BPA	15:48:52.807	RAS-ACA, BRAKE, HIGH GEN DROP ALGORITHIM OPERATE	

EVENT #	MEMBER	TIME (PAST)	EVENT	RESTORED
113	PG&E	15:48:52.815	MALIN-ROUND MT.#2 500-KV LINE OPEN ENDED, 3 POLE, AT MALIN. THERE IS NO RELAY ACTIVITY OBSERVED AT ROUND MT. TERMINAL INITIALLY	
114	BPA	15:48:52.824	MALIN PCB 4019 TRIP (CAPJ2/SOBUS); DROPS PACIFICORP 500/230 TRANSFORMER @ MALIN	
115	APS	15:48:52.831	FOUR CORNERS MIDWAY RAS SEP SIGNAL RECV	
116	PG&E	15:48:52.838	MALIN-ROUND MT. #1 500-KV OPEN ENDED, 3 POLE, AT MALIN, POSSIBLY BY RAS SIGNAL. THERE IS NO RELAY ACTIVITY OBSERVED AT ROUND MT. TERMINAL	1829
117	BPA	15:48:52.855	RAS-ACB, INTERTIE SEPARATION, BRAKE, ALGORITHIM OPERATE	
118	BPA	15:48:52.878	GRIZZLY-SUMMER LAKE OPEN AT GRIZZLY; OPEN AT SUMMER LAKE AT 52.907; ONLY PGE ROUND BUTTE GENERATION REMAINS CONNECTED TO GRIZZLY BUS. LAST LINE BREAKER AT GRIZZLY TRIPS AT 15:50:27.690	Grizzly Summer Lake @ 16:43; Grizzly Round Butte @ 17:12
119	BPA	15:48:52.892	MALIN 230-KV PCB 1L1 TRIP (PACW 500/230 BK) TRIP	
120	BPA	15:48:52.915	MALIN-WARNER 230-KV (PCB 1L12 OPEN)	16:30??
121	BPA	15:48:52.919	RAS-ACA SENDS GEN DROP TO RRPH, CHJO, WLPH, WAPH, GCTW	
122	BPA	15:48:52.987	MALIN SHUNT CAPS GROUPS 3 & 4 OPEN	
123	PG&E	15:48:53	ROUND MT.-TABLE MT. #2 500-KV LINE OPEN ENDED AT ROUND MT	
124	PAC	15:48:53.255	MALIN-SUMMER LAKE OPENS AT SUMMER LAKE; SEPERATING MALIN FROM MIDPOINT; MALIN TERMINAL OPENS AT 53.258. 500-KV BUS AT MALIN, SUMMER LAKE AND CAPTAIN JACK ARE DEAD. ALL 500 BREAKERS AT MALIN AND SUMMER LAKE ARE OPEN	Summer Lake Malin @ 16:52; Midpoint Summer Lake @ 16:43
125	IPC	15:48:53.412	MIDPOINT-SUMMER LAKE TRIP AT MIDPOINT (TRANSFER TRIPPED FROM SUMMER LAKE)	1643
126	BPA	15:48:53.500	CELILO 500 AC CONVERTER 1 & 2 DC DOWN TO 0 MW	
127	MPC	15:48:53.622	COLSTRIP 3 & 4 RELAYED OFF LINE	1707; #4 8/11 @ 0429
128	MPC	15:48:53.649	COLSTRIP 1 RELAYED OFF LINE	1656
129	WAUC	15:48:53.708	GLEN CANYON-SIGURD 230-KV LINE RELAYED BY OUT-OF-STEP	18:53:09
130	TSGT	15:48:54	HESPERUS-MONTROSE 345-KV LINE TRIPPED AT MONTROSE, ZONE 1	
131	BPA	15:48:54.100	CELILO 230 AC CONVERTER 3 & 4 DC DOWN TO 290 MW	
132	LDWP	15:48:54.360	SYLMAR CONVERTER STATION – REACTIVE POWER CONTROLLER TURNED OFF	
133	APS	15:48:54.415	FOUR CORNER-PINTO 345-KV LINE TRIPPED BY OUT-OF-STEP	18:49:53
134	APS	15:48:54.435	WEST PHOENIX GT2 TRIP BY UF	1628
135	SRP	15:48:54.576	NORTH GILA-IMPERIAL VALLEY TRIP	
136	SCE/SRP	15:48:54.622	PALO VERDE DEVERS 500 TRIP AT PALO VERDE; @ DEVERS @ 54.625	1809
137	SCE	15:48:54.700	MIDWAY-VINCENT 1 TRIP OUT-OF-STEP	1847
138	SCE	15:48:54.700	MIDWAY-VINCENT 2 TRIP OUT-OF-STEP	1848
139	WAUC	15:48:54.703	SHIPROCK-LOST CANYON 230-KV LINE RELAYED. OUT-OF-STEP TRIP	1853
140	PG&E	15:48:54.765	MIDWAY-VINCENT #3 500-KV LINE TRIPPED DUE TO VOLTAGE COLLAPSE (NORTHERN CALIFORNIA NOW SEPARATED FROM SOUTHERN CALIFORNIA)	1847
141	APS	15:48:54.825	NAVAJO-MOENKOPI 500 TRIP AT NAVAJO; AT MOENKOPI @ 54.827	
142	WAUC	15:48:54.846	CURECANTI TERMINAL OF THE CURECANTI-MONTROSE 115-KV LINE RELAYED. ZONE 1	
143	TSGT	15:48:54.934	HESPERUS-WATERFLOW 345-KV LINE TRIPPED AT HESPERUS, OUT-OF-STEP	
144	WAUC	15:48:54.934	MONTROSE-HESPERUS 345-KV LINE RELAYED. UNIFLEX Z1P TRIP	1853
145	WAUC	15:48:54.936	HESPERUS TERMINAL OF THE WATERFLOW-HESPERUS 345-KV LINE OOS TRIP	1853
146	WAUC	15:48:54.938	CITY OF FARMINGTON, NM GLADE TAP-DURANGO 115-KV TIE OPENED AT GLADE TAP. OOS TRIP (TOTE 2 SEPARATION NOW COMPLETE)	1857
147	TSGT	15:48:54.962	HESPERUS-MONTROSE 345-KV LINE TRIPPED AT HESPERUS, ZONE 1	

EVENT #	MEMBER	TIME (PAST)	EVENT	RESTORED
148	APS	15:48:54.975	BUCKEYE BK162 OPENED (#2 XFMR)	
149	APS	15:48:54.975	BUCKEYE BK562 OPENED (#6 XFMR)	
150	LDWP	15:48:55	SYLMAR CONVERTER STATION - VOLTAGE AT 68 PERCENT	
151	SMUD	15:48:55	CAR: FREQUENCY @ 58.7 HZ, CB 7010 TRIPPED OPEN, UNDERFREQUENCY RELAY	
152	SMUD	15:48:55	ELV 69-KV CB'S 6150 & 6158 TRIPPED OPEN, UNDERFREQUENCY RELAY.FTL: 69-KV CB'S 7102, 7106 & 7110 TRIPPED OPEN, UNDERFREQUENCY RELAY.HED: 69-KV CB 6306 TRIPPED OPEN UNDERFREQUENCY RELAY.ORV: 69-KV CB'S 682, 6802, 6806, 6818 & 6838 TRIPPED OPEN, UF	
153	TSGT	15:48:55.007	MONTROSE-NUCLA 115-KV LINE TRIPPED AT MONTROSE, TT RAS FROM THE MONTROSE-HESPERUS 345-KV LINE TRIP	
154	PG&E	15:48:55.141	DIABLO CANYON UNIT #2 TRIPPED	8/15 @1431
155	PG&E	15:48:55.405	DIABLO CANYON UNIT #1 TRIPPED	8/19 @ 0410
156	APS	15:48:55.565	YUMA CO-GEN TRIPPED OFF LINE	
157	WAUC	15:48:55.673	GLEN CANYON-POWELL 69-KV LINE RELAYED, APPROX. 16 MW OF CITY OF PAGE, AZ LOAD INTERRUPTED	
158	WAUC	15:48:55.679	GLEN CANYON-BUCKSKIN 138-KV LINE RELAYED, APPROX. 20 MW OF GARKANE ELECTRIC ASSOCIATION LOAD INTERRUPTED	
159	SRP	15:48:55.951	HORSE MESA UNIT 1 TRIPPED	
160	MID	15:48:56	UFLS	
161	SMUD	15:48:56	HED: 69-KV CB 6322 TRIPPED OPEN, UNDERFREQUENCY RELAY	
162	BPA	15:48:56.100	CELILO 500 AND 230 RESTART TO 850 + 1500 MW	
163	NEVP	15:48:57	DECATUR WESTSIDE HARRY ALLEN 230-KV LINE TRIPPED	15:58:17
164	WAMP	15:48:57	FOLSOM ROSEVILLE LINE TRIPPED -- OVERVOLTAGE	1751
165	WAMP	15:48:57	FOLSOM UNITS TRIP	1751
166	WAMP	15:48:57	NIMBUS UNITS TRIP	1800
167	LDWP	15:48:58	SYLMAR CONVERTER STATION - CONVERTERS 1 & 2 TRIPPED, LOSS OF COOLING	
168	PSNM	15:48:58	115-KV SANDIA, WEST MESA CAP BANKS TRIP	
169	WALC	15:48:58	BLYTHE: NILAND LINE PCB 472 RELAYED	1555
170	WALC	15:48:58	HEADGATE ROCK: APS 34.5 LINE PCB 142 RELAYED	1621
171	WALC	15:48:58	HEADGATE ROCK: PCB 1052 RELAYED	1620
172	WALC	15:48:58	HEADGATE ROCK: TRANSFORMER PCB 152 RELAYED	1619
173	WALC	15:48:58	VALLEY FARMS: PCB 362 RELAYED	1819
174	BPA	15:48:58.200	CELILO 500 DOWN TO 170 WM, CELILO 230 DOWN TO 475 MW	
175	BPA	15:48:58.251	KEELER SVC TRIP DUE TO LOW VOLTAGE ON COOLING, VOLTAGE @ 156 KV WHEN UNDERVOLTAGE TRIPPED. (.68 PU)	1549
176	APS	15:48:58.496	NAVAJO-MCCULLOUGH 500-KV LINE (A-B FAULT)	
177	APS	15:48:58.803	NAVAJO-WESTWING 500-KV LINE TRIP AT NAVAJO; AT WESTWING @ 58.809	
178	SCE	15:48:58.980	ORMOND BEACH 2 TRIP	1915
179	PSNM	15:48:59	72 MVAR GUADALUPE REACTOR TRIP	
180	PSNM	15:48:59	BB 345-KV LINE AND BLACKWATER DC CONVERTER TRIP	
181	BPA	15:48:59.100	CELILO 500 RESTART UP TO 500 MW, CELILO 230 TO 1,000 MW	
182	APS	15:48:59.341	NAVAJO UNIT #1 TRIP BY SMF FILTER RELAY	2215
183	APS	15:48:59.492	NAVAJO UNIT #2 TRIP BY SMF FILTER RELAY	8/11 @ 1251
184	BPA	15:48:59.878	GRIZZLY-SUMMERLAKE OPEN AT GRIZZLY	
185	BCH	15:49	5L31 TRIPPED ON OV -- 571 KV	1606
186	CFE	15:49	PJZ-U06 TRIPPED -- BOILER TROUBLE -- 142 MW	
187	CFE	15:49	UFLS @ 59.1, 58.9 HZ	

AUGUST 10, 1996 WSCC DISTURBANCE–SEQUENCE OF EVENTS

EVENT #	MEMBER	TIME (PAST)	EVENT	RESTORED
188	EPE	15:49	UNDERFREQUECY LOAD SHED INITIATES	
189	IPC	15:49	C.J. STRIKE UNIT #3 TRIP (28 MW)	1614
190	IPC	15:49	CLEAR LAKE GENERATION TRIP (1 MW)	1635
191	IPC	15:49	MILNER UNIT #3 TRIP (2 MW)	1549
192	LDWP	15:49	POWER PLANT 1, UNITS 1,5 TRIP	
193	SMUD	15:49	ECC: FIRST INDICATION OF MAJOR SYSTEM PROBLEM, MULTIPLE EMS AUDIBLE ALARMS, EMS SHOWS MANY LOW VOLTAGE ALARM BURST BEING LOGGED BY EMS	
194	SRP	15:49	MORMON FLAT UNIT 1, 2 TRIP	
195	SRP	15:49	STEWART MOUNTAIN UNIT TRIPPED	
196	TAUC	15:49	COWLEY RIDGE/US WIND TRIP 16.5 MW; OF	1630
197	TAUC	15:49	DICKSON DAM TRIP 6 MW; OF	1630
198	TAUC	15:49	DRAYTON VALLEY POWER TRIP 10.6 MW; OF	1715
199	TAUC	15:49	EAGLE RIVER POWER TRIP 21 MW; OF	1715
200	TAUC	15:49	WELDWOOD TRIP 5 MW; OF	1719
201	TSGT	15:49	NUCLA 1,2,3,4, 80 MW TRIPPED	
202	WAMP	15:49	FOLSOM CONTROL CENTER UPS SWITCHED TO BATTERY DUE TO UNDERFREQUENCY	00:00
203	WAUC	15:49	GLEN CANYON UNITS 2, 5, 7, AND 8 TRIPPED VIA REMEDIAL ACTION SCHEME WHILE CARRYING APPROXIMATELY 430 MW. CAUSED BY LOSS OF BOTH GLEN CANYON-FLAGSTAFF 345-KV LINES	
204	SDGE	15:49	SOUTHERN ISLAND LOST LOAD; 57 MW; 13,086 CUSTOMERS	1745
205	WAUC	15:49	WILLIAMS FIELD SERVICE MILAGRO UNITS 1 AND 2 RELAYED WHILE CARRYING 60 MW	
206	SCE	15:49:00.829	VINCENT-WESTWING 230-KV TRIP – UF	1904
207	BPA	15:49:01.000	CELILO 500 DOWN TO 270 MW, CELILO 230 DOWN TO 900 MW	
208	LDWP	15:49:01	SYLMAR CONVERTER STATION – VG 7 TRIPPED ON PERMISSIVE	
209	MID	15:49:01	WOODLAND GENERATOR TRIPPED	
210	PSNM	15:49:01	65 MVAR WEST MESA REACTOR TRIP	
211	APS	15:49:01.650	DEER VALLEY DV2042 OPENED (12KV FEEDER #20)	
212	APS	15:49:01.650	DEER VALLEY DV2142 OPENED (12KV FEEDER #21)	
213	APS	15:49:01.660	DEER VALLEY DV1342 OPENED (12KV FEEDER #13)	
214	APS	15:49:01.660	DEER VALLEY DV1442 OPENED (12KV FEEDER #14)	
215	APS	15:49:01.660	DEER VALLEY DV942 OPENED (12KV FEEDER #9)	
216	APS	15:49:01.710	GILA BEND GB1242 OPENED (12KV FEEDER #12)	
217	APS	15:49:01.710	GILA BEND GB2242 OPENED (12KV FEEDER #22)	
218	APS	15:49:01	SOUTHERN ISLAND LOAD LOST – 2,000 MW; 300,000 CUSTOMERS	2030
219	MWD	15:49:01.950	CITY OF ANAHEIM LOAD SHED – 120 MW	
220	MWD	15:49:01.950	MWD UFLS @ 59.1, 1736 MW TOTAL	
221	SCE	15:49:01.950	CDWR PUMP LOADS SHED 194 MW	2400
222	SCE	15:49:01.950	DEVERS 115-KV UFLS 621 MW	1841
223	SCE	15:49:01.950	LA CIENEGA 66-KV UFLS 260 MW	1835
224	SCE	15:49:01.950	LA FRESA A 66-KV UFLS 141 MW	1841
225	SCE	15:49:01.950	SAN BERNARDINO 66-KV UFLS 353 MW	1843
226	SCE	15:49:01.950	SCE F @ 59.1, MWD PUMP LOADS SHED – 290 MW	2220
227	SCE	15:49:01.950	WALNUT 66-KV UFLS 361 MW	1835
228	SDGE	15:49:03	NAVAL TRAINING CENTER QF TRIPPED WHILE CARRYING 22 MW OF LOAD	
229	SMUD	15:49:03	EMC: AGC LOW FREQUENCY ALARM RETURNED TO NORMAL, FREQUENCY @ 59.974 HZ. AGC LFC CONTROL MODE OFF	

EVENT #	MEMBER	TIME (PAST)	EVENT	RESTORED
230	LDWP	15:49:04	INTERMOUNTAIN 1 - SMF RELAY OPERATION (SSO PROTECTION) - 854 MW	18:05:22
231	WALC	15:49:04	KNOB: PILOT KNOB-DESALTER LINE PCB 272 RELAYED	1556
232	WALC	15:49:04	KNOB: PILOT KNOB-GILA LINE PCB 172 RELAYED	1556
233	WALC	15:49:04	MCCONNICO: DAVIS-HARRIS LINE PCB 582 RELAYED	1658
234	WALC	15:49:04	MCCONNICO: PRESCOTT-HARRIS LINE PCB 782 RELAYED	1700
235	SMUD	15:49:05	POC: 69-KV CB 6922 CLOSED, CUSTOMER LOAD PICKED UP	
236	LDWP	15:49:06	CASTAIC 1 TRIPPED – UNDEREXCITATION – IN CONDENSE	18:15:28
237	LDWP	15:49:07	RS-B BANK D – UF TRIP AT 59.1 HZ (SCADA REPORT)*	17:04:55
238	LDWP	15:49:07	RS-G BANK B – UF TRIP AT 59.1 HZ (SCADA REPORT)*	17:38:39
239	LDWP	15:49:07	RS-J BANK A - UF TRIP AT 59.1 HZ (SCADA REPORT)*	17:38:57
240	LDWP	15:49:07	RS-T BANK A – UF TRIP AT 59.1 HZ (SCADA REPORT)*	17:33:25
241	LDWP	15:49:07	RS-T BANK C – UF TRIP AT 59.1 HZ (SCADA REPORT)*	17:33:32
242	APS	15:49:07.140	NAVAJO UNIT #3 TRIP BY MAIN FUEL TRIP	8/12 @ 0720
243	SRP	15:49:08	BRANDOW-WARD 230-KV LINE TRIPPED	
244	LDWP	15:49:10	HAYNES 3 TRIPPED – 230 MW	18:02:11
245	SMUD	15:49:10	EMC: EMS SHOWING HIGH SYSTEM FREQUENCY RETURNING TOWARD 60 HZ @ 60.5 HZ ELV: 69-KV CB'S 1152 & 1252 OPENED, CAP BANKS DE-ENERGIZED	
246	MWD	15:49:11.110	MWD UFLS @ 58.9, 1433 MW TOTAL	
247	SCE	15:49:11.110	CENTER B 66-KV UFLS 214 MW	1804
248	SCE	15:49:11.110	DEL AMO 66-KV UFLS 343 MW	1834
249	SCE	15:49:11.110	JOHANNA 66-KV UFLS 219 MW	1841
250	SCE	15:49:11.110	RECTOR 66-KV UFLS 435 MW	1823
251	SCE	15:49:11.110	SCE F=58.9	
252	APS	15:49:11.364	BUCKEYE BK1042 OPENED (12KV FEEDER #10)	
253	APS	15:49:11.365	BUCKEYE BK842 OPENED (12KV FEEDER #8)	
254	PSNM	15:49:12	UNDERFREQUENCY LOAD SHED 360 MW	
255	APS	15:49:12.510	FOUR CORNER UNIT #5 TRIP BY HIGH FURNACE PRESSURE	8/11 @ 0222
256	APS	15:49:13.315	PALO VERDE UNIT #1 TRIP BY DNBR REACTOR TRIP	8/12 @ 1454
257	APS	15:49:13.405	PALO VERDE UNIT #3 TRIP BY DNBR REACTOR TRIP	8/11 @ 1756
258	WALC	15:49:14	DAVIS DAM: UNIT #2 PCB 282 RELAYED	1659
259	WALC	15:49:14	GILA: 4.16-KV PUMP PLANT PCB 106 RELAYED	1632
260	WALC	15:49:14	GILA: GILA VALLEY PCB 342 RELAYED	1937
261	WALC	15:49:14	HILLTOP: TRANSFORMER PCB 382 RELAYED	1602
262	WALC	15:49:14	HOOVER DAM: UNIT N2 PCB N224 RELAYED	1916
263	WALC	15:49:14	HOOVER DAM: UNIT N3 PCB N324 RELAYED	
264	WALC	15:49:14	HOOVER DAM: UNIT N8 PCB N824 RELAYED	1613
265	WALC	15:49:14	WELLTON-MOHAWK: 34.5-KV PUMP PLNT #1 PCB 442 RELAYED	1612
266	WALC	15:49:14	WELLTON-MOHAWK: 34.5-KV PUMP PLNT #3 PCB 642 RELAYED	1605
267	WALC	15:49:14	WELLTON-MOHAWK: 4.16-KV PUMP PLNT #2 PCB 1512 RELAYED	1621
268	LDWP	15:49:15	RS-B BANK B – UF TRIP AT 58.9 HZ (SCADA REPORT)*	17:04:48
269	LDWP	15:49:16	RS-S BANK C – UF TRIP AT 58.9 HZ (SCADA REPORT)*	17:20:12
270	LDWP	15:49:17	RS-E BANK A – UF TRIP AT 58.9 HZ (SCADA REPORT)*	17:31:25
271	BPA	15:49:18	CELILO 230 UP TO 1290 MW, DROPS TO 1235 MW	
272	BPA	15:49:18	CELILO 500 UP TO 425 MW, DROPS TO 350 MW	
273	LDWP	15:49:18	RS-G BANK C – UF TRIP AT 58.9 HZ (SCADA REPORT)*	17:12:32
274	APS	15:49:20.830	PINNACLE PEAK-PINNACLE PEAK (WAPA)	
275	SCE	15:49:23.315	PALO VERDE #1 TRIP	

EVENT #	MEMBER	TIME (PAST)	EVENT	RESTORED
276	SDGE	15:49:24	ENCINA UNIT 4 TRIPPED WHILE CARRYING 118 MW OF LOAD	1632
277	SMUD	15:49:24	SLAB CREEK UNIT TRIPPED OFF LINE.FTL: 69-KV CB 7110 CLOSED, CUSTOMER LOAD PICKED UP	
278	SRP	15:49:24.266	AGUA FRIA UNIT 3 TRIP	
279	LDWP	15:49:26	MARKETPLACE 500-KV SVC TRIPPED	
280	SDGE	15:49:28	ENCINA UNIT 5 TRIPPED WHILE CARRYING 205 MW OF LOAD	1636
281	LDWP	15:49:29	ADELANTO 500-KV SVC TRIPPED	
282	SMUD	15:49:37	CAM: UNIT 1 13-KV CB 310 TRIPPED OPEN, UNIT 1 OFF LINE AND SHUTTING DOWN.	
283	SMUD	15:49:40	FTL: 69-KV CB'S 7102 & 7106 CLOSED, CUSTOMER LOAD PICKED UP.UNV: UNIT 13-KV CB 500 TRIPPED OPEN, UNIT OFF LINE AND SHUTTING DOWN	
284	NEVP	15:49:41	GENERATION DROPPED 1,127 MW	21:25
285	SMUD	15:49:42	FTL: 69-KV CB 7102 TRIPPED OPEN, ?	
286	NEVP	15:49:43	LOAD SHED -- 1,544 MW	21:25
287	WAUC	15:49:44.845	GLEN CANYON 345-KV BUS @ 506 KV	
288	WAUC	15:49:45.271	GLEN CANYON TERMINALS OF THE GLEN CANYON-FLAGSTAFF NO. 1 AND 2 345-KV LINES RELAYED. EAST BUS 86 LOR	
289	WAMP	15:49:47.366	OLINDA 500/230 TRANSFORMER TRIP ON OVERVOLTAGE	
290	WALC	15:49:48	PINNACLE PEAK: 345-KV BUS PCB 1692 RELAYED	1746
291	WALC	15:49:48	PINNACLE PEAK: FLAGSTAFF-PPK #1 LINE RELAYED	
292	WALC	15:49:48	PINNACLE PEAK: FLAGSTAFF-PPK #2 LINE RELAYED	
293	TSGT	15:49:50	LOST CANYON – CO2 115-KV LINE TRIPPED AT LOST CANYON, ZONE 1	
294	TSGT	15:49:50	LOST CANYON-SHIPROCK 230-KV LINE TRIPPED AT LOST CANYON, OOS	
295	WALC	15:49:50	PINNACLE PEAK: 230-KV BANK #1 PCB 182 RELAYED	1743
296	WALC	15:49:50	PINNACLE PEAK: 230-KV BANK #2 PCB 1982 RELAYED	1743
297	WALC	15:49:50	PINNACLE PEAK: 230-KV BANK #3 PCB 2282 RELAYED	1743
298	WALC	15:49:50	PINNACLE PEAK: 230-KV S. SHUNT BANK PCB 3782 RELAYED	1743
299	WAMP	15:49:51.899	TRACY 500/230 TRANSFORMER TRIP ON OVERVOLTAGE	1743
300	APS	15:49:58.855	PINNACLE PEAK PP1622 OPENED (230-KV CAP BANKS #1, #2 & #3)	1743
301	SCE	15:49:59.723	MOHAVE #2 TRIP	
302	TEP	15:50	SPRINGERVILLE #2 TRIP	0202 8/11
303	BPA	15:50	LAPINE-CHILOQUIN 230-KV	16:28
304	BPA	15:50	LAPINE-FORT ROCK 115-KV	16:28
305	BPA	15:50	LAPINE-MIDSTATE ELECTRIC 115-KV	16:27
306	BPA	15:50	PILOT BUTTE-LAPINE 230-KV	16:27
307	BPA	15:50	REDMOND-PPL 115-KV	16:03
308	BPA	15:50	REDMOND-PPL 230-KV PILOT BUTTE (A-252)	16:23
309	PG&E	15:50	HUNTERS POINT #2 UNIT RELAYED	1755
310	PG&E	15:50	MORRO BAY UNIT #1 RELAYED VIA LOSS OF FIELD	2301
311	PG&E	15:50	MORRO BAY UNIT #2 RELAYED VIA GENERATOR UNDERVOLTAGE	2000
312	PG&E	15:50	MORRO BAY UNIT #3 RELAYED VIA GENERATOR UNDERVOLTAGE	2318
313	PG&E	15:50	MORRO BAY UNIT #4 RELAYED	
314	SCE	15:50:00.000	SILVER PEAK 55-KV SCE/SPP TIE TRIP @ SILVER PEAK (TIE BETWEEN NORTHERN NEVADA & SOUTHERN CALIFORNIA OPEN)	1905
315	WAMP	15:50	STAMPEDE UNIT 2 TRIP – BAD TEMPERATURE PROBE	
316	WAUC	15:50	REQUESTED LOAD REDUCTIONS OF 200 MW EACH AT TRI-STATE CRAIG AND DESERET G&T BONANZA PLANTS TO REDUCE HIGH FREQUENCY ON NORTH SYSTEM	
317	SCE	15:50:21.790	OLINDA 66-KV UFLS @ 58.9 222MW	1802

EVENT #	MEMBER	TIME (PAST)	EVENT	RESTORED
318	OXGC	15:50:48	TURBINE GENERATOR TRIPPED	
319	SMUD	15:50:57	CAR: 69-KV CB 7010 CLOSED, CUSTOMER LOAD PICKED UP	
320	**EPE**	**15:51**	**NEWMAN GENERATOR NO. 1 TRIPS**	**2022**
321	MWD	15:51	MWD PUMP LOADS SHED, 290 MW	
322	**PG&E**	**15:51**	**TIGER CREEK-BELLOTA #2 230-KV LINE (TIGER CREEK P.H.-VALLEY SPRINGS SECTION) RELAYED AND NO TEST MADE**	
323	SDGE	15:51	SOUTHERN ISLAND LOAD LOST; 118 MW; 63,624 CUSTOMERS	1846
324	LDWP	15:51:24	RS-J BANK C – UF TRIP AT 58.7 HZ (SCADA REPORT)*	17:10:35
325	LDWP	15:51:47	RS-J BANK B – UF TRIP AT 58.7 HZ (SCADA REPORT)*	17:11:28
326	**PG&E**	**15:51:47.420**	**MOSS LANDING UNIT #7 TRIPPED VIA LOSS OF FIELD DUE TO SYSTEM OSCILLATIONS**	**8/11 @1800**
327	SMUD	15:51:52	EMS: LAK & HUR FREQUENCY @ 59.17 HZ.CAR: 69-KV CB 7010 TRIPPED OPEN, UNDERFREQUENCY RELAY	
328	**TEP**	**15:52**	**SPRINGERVILLE #1 TRIP**	**2131**
329	CFE	15:52	UFLS @ 58.7 HZ	
330	MWD	15:52	MWD HYDRO GEN TRIPPED – 63.2 MW	
331	PG&E	15:52	PIT #7 P.H. #1 UNIT RELAYED	1641
332	SCE	15:52:13.250	ANTELOPE 66-KV UFLS 348 MW	1855
333	SCE	15:52:13.250	GOULD 66-KV UFLS 82 MW	1747
334	SCE	15:52:13.250	LAGUANA BELL 66-KV UFLS 146 MW	1800
335	SCE	15:52:13.250	LIGHTHIPE AB 66-KV UFLS 125 MW	1733
336	SCE	15:52:13.250	SANTIAGO 66-KV UFLS 496 MW	1755
337	SCE	15:52:13.250	SCE F@58.7	
338	MWD	15:52:13.750	MWD UFLS @ 58.7, 1,197 MW TOTAL	
339	**PG&E**	**15:52:17.536**	**MOSS LANDING UNIT #6 TRIPPED BY VOLTS/HERTZ, REGULATOR VOLTAGE BALANCE, STARTUP OVERVOLTAGE RELAY**	**8/11 @0411**
340	SMUD	15:52:22	EMS: FTL FREQUENCY @ 58.66 HZ.FTL: 69-KV CB'S 7106 & 7110 TRIPPED OPEN, UNDERFREQUENCY RELAY	
341	SMUD	15:52:26	HED: 69-KV CB 6346 TRIPPED OPEN UNDERFREQUENCY RELAY	
342	LDWP	15:52:48	CASTAIC 2 SYNCHRONIZED	
343	BPA	15:53:25.601	CAPTAIN JACK PCB 4996 OPEN; ALL BREAKERS OPEN AT CAPTAIN JACK	Captain Jack Malin 1 @ 16:52; Captain Jack Malin 2 @ 16:53
344	BCH	**15:54**	**5L94 TRIPPED ON UV, 370 KV (TIE TO ALBERTA OPEN)**	**1629**
345	BCH	15:54	777L TRIP	1919
346	BCH	15:54	786L TRIP	1632
347	BCH	15:54	FORT NELSON UFLS	
348	BCH	15:54	NTL TI TRIP	1919
349	PG&E	15:54	FRESNO AREA LOAD MANUALLY REDUCED 80 MW TO HELP RECOVER SYSTEM FREQUENCY	
350	SDGE	15:54	SOUTHERN ISLAND LOAD LOST; 54 MW; 47,582 CUSTOMERS	1800
351	PG&E	15:54:00	SYSTEM FREQUENCY 58.3 HZ. PG&E DROPS UNDERFREQUENCY LOAD BLOCK 7	
352	LDWP	15:54:03	RS-E BANK D – UF TRIP AT 58.7 HZ (SCADA REPORT)*	17:13:30
353	TAUC	15:54:09	A740SGEN1(HRM) TRIP 87 MW TRIP MW; OVERSPEED	2033
354	LDWP	15:54:15	RS-E BANK C – UF TRIP AT 58.7 HZ (SCADA REPORT)*	17:15:12
355	SMUD	15:55:02	ELV: 69-KV CB 6166 TRIPPED OPEN, UNDERFREQUENCY RELAY, ANDPOC: 69-KV CB 6922 TRIPPED OPEN, UNDERFREQUENY RELAY	
356	USBR	15:55:02.182	PLANT COMPUTER AT SHASTA FAILED	

AUGUST 10, 1996 WSCC DISTURBANCE–SEQUENCE OF EVENTS

EVENT #	MEMBER	TIME (PAST)	EVENT	RESTORED
357	LDWP	15:55:15	CASTAIC 4 SYNCHRONIZED	
358	LDWP	15:55:28	SCATTERGOOD 3 TRIPPED - 235 MW	21:44:56
359	PG&E	15:56	CONTRA COSTA UNIT #6 RELAYED VIA LOSS-OF-FIELD RELAY	1843
360	PG&E	15:56	CONTRA COSTA UNIT #7 RELAYED VIA LOSS OF FIELD RELAY	
361	SMUD	15:56	EMC: IN RESPONSE TO PERSISTENT LOW SYSTEM FREQUENCY, POWER SYSTEM OPERATORS BEGAN MANUALLY INCREASING LOAD OF ALL ON-LINE SMUD GENERATING UNITS	
362	PG&E	15:56:03	PG&E ISLAND SYSTEM FREQUENCY 58.3 HZ. PG&E DROPS UNDERFREQUENCY LOAD BLOCKS 8 THROUGH 10. IN ADDITION, MARTIN INTERCHANGE OPENS ISLANDING THE CITY OF SAN FRANCISCO FROM THE REST OF PG&E	
363	LDWP	15:56:20	CASTAIC 6 SYNCHRONIZED	
364	WALC	15:56:30	PINNACLE PEAK: REACTOR BANK KW5B PCB 8034 CLOSED	
365	WALC	15:56:40	PINNACLE PEAK: REACTOR BANK KW3B PCB 7334 CLOSED	
366	WALC	15:56:49	PINNACLE PEAK: REACTOR BANK KW3A PCB 7234 CLOSED	
367	WALC	15:57:02	PINNACLE PEAK: REACTOR BANK KW2A PCB 7034 CLOSED	
368	WALC	15:57:16	PINNACLE PEAK: REACTOR BANK KW2B PCB 7134 CLOSED	
369	WALC	15:57:24	PINNACLE PEAK: REACTOR BANK KW4A PCB 8334 CLOSED	
370	WALC	15:57:32	PINNACLE PEAK: REACTOR BANK KW5A PCB 8134 CLOSED	
371	WALC	15:57:41	PINNACLE PEAK: REACTOR BANK KW4B PCB 8234 CLOSED	
372	SMUD	15:57:54	POC: 69-KV CB'S 696, 6914, 6918 & 6926 TRIPPED OPEN, UNDERFREQUENCY RELAY	
373	SMUD	15:57:56	HUR: 69-KV CB 6706 TRIPPED OPEN, UNDERFREQUENCY RELAY	
374	SMUD	15:58:01	ROB: UNIT 13-KV CB 600 TRIPPED OPEN, UNIT OFF LINE & SHUTTING DOWN, RELAY TARGETS?	
375	PSNM	15:58:46	BB 345-KV LINE AND BLACKWATER DC CONVERTER RESTORED	
376	BPA	15:59	CELILO MANUALLY RAMPED TO 0 MW	
377	SRP	15:59:03.506	CORONADO UNIT 2 TRIPPED	
378	APS	16:00	NORTH GILA-MIGUEL – UNKNOWN TIME	
379	APS	16:00	PALO VERDE-DEVERS – UNKNOWN TIME	
380	LDWP	16:00	PP2-3 RESYNCHRONIZED	
381	SMUD	16:00:00	EMC: IN RESPONSE TO VERY HIGH TRANSMISSION SYSTEM VOLTAGES, POWER SYSTEM OPERATORS STARTED SWITCHING CAPACITOR BANKS OUT OF SERVICE	
382	WAPA	16:00	APPROX. CONFERENCEE CALL VIA WSCC RINGDOWN CIRCUIT INDICATES CALIFORNIA IS SEPARATED FROM THE PACIFIC NORTHWEST AT COB. BONNEVILLE POWER AUTHORITY INDICATES THEY REMAIN TIED TO IDAHO AND MONTANA	
383	WAPA	16:00	COMPARISON OF FREQUENCY READING INDICATES NO SEPARATION BETWEEN WACM CONTROL AREA AND THE PACIFIC NORTHWEST THROUGH THE NORTHERN UTILITIES. SUBSEQUENT REPORTS INDICATE SOUTHERN AND NORTHERN CALIFORNIA ARE ALSO SEPARATED BETWEEN MIDWAY AND VINCENT	
384	SMUD	16:00:40	POC: 69-KV CB 6914 & 6918 CLOSED, CUSTOMER LOAD PICKED UP	
385	SMUD	16:00:42	POC: 69-KV CB 6926 CLOSED, CUSTOMER LOAD PICKED UP	
386	LDWP	16:00:56	CASTAIC 3 SYNCHRONIZED	
387	APS	16:01	OCOTILLO ST2 TRIP BY LOW DRUM LEVEL	1722
388	SMUD	16:01:48	UNV: UNIT 13-KV CB 500 CLOSED, UNIT SYNCHRONIZED TO THE SYSTEM	
389	SMUD	16:01:48	UNV: UNIT 13-KV CB 500 TRIPPED OPEN, UNIT SHUTTING DOWN, RELAY TARGETS?	
390	LDWP	16:02	PP1-1 RESYNCHRONIZED	
391	PSNM	16:02:06	BLACKWATER RAMPED TO 100 MW WEST	
392	APS	16:02:37.600	CHOLLA UNIT #1 TRIP BY UF	1759

EVENT #	MEMBER	TIME (PAST)	EVENT	RESTORED
393	APS	16:04	OCOTILLO GT2 TRIP BY UF	1604
394	SDGE	16:04	SOUTHERN ISLAND LOAD LOST; 54 MW; 47,582 CUSTOMERS	1808
395	BPA	16:04	CELILO VALVEGROUP 2	
396	LDWP	16:04	SYLMAR GROUP 8	
397	SDGE	16:04	SOUTH BAY UNIT 1 TRIPPED WHILE CARRYING 146 MW OF LOAD	1636
398	LDWP	16:04:12	SYLMAR CONVERTER STATION -- VG 8 TRIPPED ON IMBALANCE PROTECTION	
399	LDWP	16:04:19	RS-F BANK C -- UF TRIP AT 58.5 HZ (SCADA REPORT)*	17:00:18
400	LDWP	16:04:19	RS-T BANK B -- UF TRIP AT 58.5 HZ (SCADA REPORT)*	
401	PSNM	16:04:20	UNDERFREQUENCY LOAD SHED 120 MW	
402	LDWP	16:05:12	RS-J BANK D -- UF TRIP AT 58.5 HZ (SCADA REPORT)*	17:09:46
403	LDWP	16:05:12	SYLMAR CONVERTER STATION -- AC FILTER BANK 4 RELAYED, BLOWN FUSES	
404	APS	16:05:26.421	GILA BEND GB862 OPENED (AJO 69-KV LINE) B TO GROUND FAULT	
405	LDWP	16:06:19	SYLMAR CONVERTER STATION -- DC RAMP TO ZERO BEGUN	
406	SCE	16:06:47.170	VALLEY 115-KV MANUAL LOAD SHED 515 MW	1725
407	WALC	16:06:54	KOFA: SHUNT CAP PCB 352 TRIPPED	
408	WALC	16:07:28	LIBERTY: REACTOR BANK 1C PCB 7334 CLOSED	
409	WALC	16:07:40	HOOVER DAM: UNIT N3 PCB N324 RELAYED	
410	WALC	16:07:43	LIBERTY: REACTOR BANK 1A PCB 7134 CLOSED	
411	SCE	16:08:00.000	VILLA PARK 66-KV MANUAL LOAD SHED 396 MW	1657
412	PG&E	16:09	TIGER CREEK-BELLOTA #2 230-KV LINE (TIGER CREEK P.H.-VALLEY SPRINGS SECTION) TESTED OK AND PLACED IN SERVICE	
413	LDWP	16:11:51	CASTAIC 5 SYNCHRONIZED	
414	SCE	16:12:00.000	CHINO 66-KV MANUAL LOAD SHED 512 MW	1658
415	LDWP	16:12:11	SYLMAR CONVERTER STATION--DC RAMP TO ZERO COMPLETE, PDCI BLOCKED	
416	WAMP	16:14	FOLSOM CONTROL CENTER LOSS CRITICAL POWER DUE TO UPS BATTERY RUNNING OUT	00:00
417	WAPA	16:14	TRI-STATE RESTORED MONTROSE-HESPERUS 345-KV LINE FOR VOLTAGE CONTROL AT HESPERUS. HESPERUS REMAINS OPEN TO WATERFLOW	
418	TEP	16:16	IRVINGTON #2 TRIP	1747
419	WAPA	16:17	GLEN CANYON TERMINAL OF THE GLEN CANYON-NAVAJO 230-KV LINE RELAYED, NAVAJO 230-KV LOADS INTERRUPTED (1 TO 2 MW APPROX.)	
420	WAPA	16:17	GLEN CANYON UNITS 1, 4, AND 6 RELAYED WHILE CARRYING APPROX. 300 MW DUE TO STATION BEING ISLANDED WITH KAYENTA LINE TRIPPED. GLEN CANYON PLANT IN THE BLACK	
421	WAPA	16:17	KAYENTA TERMINAL OF THE KAYENTA-LONGHOUSE VALLEY-NAVAJO 230-KV LINE RELAYED INTERRUPTING APPROX. 25 MW OF NAVAJO TRIBAL UTILITY ASSOCIATION LOAD	
422	WAPA	16:17	KAYENTA TERMINAL OF THE SHIPROCK-KAYENTA 230-KV LINE RELAYED	
423	WAPA	16:17	LONGHOUSE VALLEY 230/69-KV TRANSFORMER RELAYED INTERRUPTING APPROX. 15 MW OF NAVAJO TRIBAL UTILITY ASSOCIATION LOAD	
424	SMUD	16:17:16	UNV: UNIT 13-KV CB CLOSED, UNIT SYNCHRONIZED TO THE SYSTEM	
425	SMUD	16:17:33	CAM: UNIT 1 13-KV CB 310 CLOSED, UNIT 1 SYNCHRONIZED TO THE SYSTEM	
426	WAUC	16:17:45.469	SHIPROCK TERMINAL, SHIPROCK KAYENTA GLEN CANYON TRIP BY GROUND TIME--GLEN CANYON NO LONGER CONNECTED TO SYSTEM. GLEN CANYON TERMINAL TRIP @ 58.576	
427	SMUD	16:19:34	EMC: AGC LFC CONTROL MODE "ON".	
428	LDWP	16:20	PP1-3 SYNCHRONIZED	
429	PSNM	16:20:15	BLACKWATER RAMPED 200 MW WEST	

EVENT #	MEMBER	TIME (PAST)	EVENT	RESTORED
430	WAPA	16:21	GLEN CANYON-NAVAJO-KAYENTA 230-KV LINE ENERGIZED FROM KAYENTA TO PROVIDE HOT BUS TO GLEN CANYON PLANT. NAVAJO TERMINAL OF GLEN CANYON-NAVAJO 230-KV LINE DIRECT TRIPPED FROM GLEN CANYON ON INDICATION OF KZ10A (PHASE SHIFTING TRANSFORMER) DIFFERENTIAL OPE	
431	WAPA	16:21	NAVAJO 230-KV LOADS RESTORED. OUT 4 MINUTES	
432	WAPA	16:24	KAYENTA 230-KV BREAKER 182 CLOSED RESTORING NAVAJO TRIBAL UTILITY ASSOC. LOADS AT KAYENTA. OUT 7 MINUTES	
433	WAPA	16:25	LONGHOUSE VALLEY 230-KV BREAKER 184 CLOSED RESTORING REMAINING NAVAJO TRIBAL UTILITY ASSOC. LOADS. OUT 8 MINUTES	
434	APS	16:28:25.590	WEST PHOENIX WP1466 CLOSED (WP GT2)	
435	SMUD	16:29:25	EMC: AGC LFC CONTROL MODE "OFF"	
436	LDWP	16:30	PP1-4 SYNCHRONIZED	
437	USBR	16:30	SHAST UNIT 2 TRIPPED–LOW GOVERNOR OIL PRES–LOSS OF STATION SERVICE	1954
438	SCE	16:31:41.000	ETIWANDA UNIT 4 TRIP (TIME UNCERTAIN)	1810
439	WAPA	16:32	GLEN CANYON UNIT 4 ON LINE FOR PLANT STATION SERVICE	
440	WAPA	16:33	GLEN CANYON 345/230-KV WEST BUS RELAYED ON OVERVOLTAGE. LOCKOUT RELAY FAILED TO RESET AUTOMATICALLY AS IT SHOULD HAVE	
441	WAPA	16:33	GLEN CANYON UNIT 6 ON LINE	
442	EPE	16:34	RIO GRANDE GENERATOR NO. 8 TRIPS	1929
443	WAPA	16:35	TRI-STATE RETURNED THE MONTROSE-NUCLA 115-KV LINE TO SERVICE	
444	SMUD	16:36:11	ELV: 69-KV CB 6166 CLOSED, CUSTOMER LOAD PICKED UP	
445	SMUD	16:37:58	HUR: 69-KV CB 6706 CLOSED, CUSTOMER LOAD PICKED UP	
446	WAPA	16:40	GLEN CANYON-NAVAJO 230-KV LINE ENERGIZED FROM NAVAJO. THIS ACTION DELAYED DUE TO NECESSITY TO MANUALLY RESET PHASE SHIFTING TRANSFORMER KZ10A DIFFERENTIAL LOCK-OUT	
447	WAPA	16:41	GLEN CANYON 230-KV BREAKER 8186 CLOSED RESTORING GARKANE ELECTRIC ASSOC. LOADS. OUT 53 MINUTES	
448	WAPA	16:41	GLEN CANYON EAST BUS ENERGIZED FROM GLEN CANYON-NAVAJO 230-KV LINE	
449	WAPA	16:44	FLAGSTAFF TERMINAL OF THE GLEN CANYON-FLAGSTAFF NO. 1 AND 2 AND PINNACLE PEAK-FLAGSTAFF NO. 1 AND 2 345-KV LINES OPENED DEAD IN PREPARATION TO RETURN THE GLEN CANYON-FLAGSTAFF-PINNACLE PEAK 345-KV LINES TO SERVICE	
450	LDWP	16:49	PP1-5 RESYNCHRONIZED	
451	SMUD	16:49:03	FTL: 69-KV CB 7102 CLOSED, CUSTOMER LOAD PICKED UP	
452	PSNM	16:50:00	BLACKWATER RAMPED TO 220 MW WEST	
453	WAPA	16:52	GLEN CANYON UNIT NO. 7 ON LINE AND LOADED TO APPROX. 120 MW (POWER FLOWING ON THE GLEN CANYON TO SHIPROCK 230-KV LINE, THEN SOUTH TO ARIZONA/NEW MEXICO)	
454	SMUD	16:53:13	POC: 69-KV CB 6922 CLOSED, CUSTOMER LOAD PICKED UP	
455	SMUD	16:53:36	ORV: 69-KV CB 6806 CLOSED, CUSTOMER LOAD PICKED UP	
456	EPE	16:55	LOAD RESTORATION INITIATED	
457	WAPA	16:58	GLEN CANYON UNIT NO. 5 ON LINE AT SPEED, NO LOAD	
458	LDWP	17:06:05	RS-T BANK D RESTORED	
459	LDWP	17:08:19	RS-G BANK D RESTORED	
460	WAPA	17:09	GLEN CANYON 69-KV BREAKER 2052 CLOSED TO PROVIDE ALTERNATE SOURCE FOR CITY OF PAGE LOADS AT SLAVENS SUBSTATION. OUT 1 HOUR 21 MINUTES. THIS ACTION DELAYED DUE TO FAILURE OF SELF RESETTING LOCKOUT ON THE GLEN CANYON WEST 230/345-KV BUS	

EVENT #	MEMBER	TIME (PAST)	EVENT	RESTORED
461	SMUD	17:10	ALL ACLM PROGRAM GROUPS & TEST GROUPS WERE ACTIVATED AS AN EMERGENCY MEASURE TO DROP ADDITIONAL CUSTOMER LOAD	
462	SMUD	17:10:53	ROB: UNIT 13-KV CB 600 CLOSED, UNIT SYNCHRONISED TO THE SYSTEM	
463	SDGE	17:12	LOAD RESTORATION BEGINS	
464	SMUD	17:13:52	ORV: 69-KV CB 6806 OPENED, CUSTOMER LOAD DROPPED	
465	EPE	17:19	EDDY TIE CLOSED	
466	SMUD	17:20:32	FTL: 69-KV CB 7102 OPENED, CUSTOMER LOAD DROPPED	
467	PG&E	17:22	PG&E ISLAND SYSTEM FREQUENCY AT 59.5 HZ. BEGAN MANUAL DEEP LOAD SHEDDING TO RESTORE SYSTEM FREQUENCY TO 60 HZ TO PARALLEL WITH BPA ON THE COI. SHED NEWARK AREA "W-1", APPROXIMATELY 500 MW	
468	SMUD	17:23	SYSTEM FREQUENCY TOOK ANOTHER HIT. PSO ELECTED TO IMPLEMENT "FAST DISPATCH" PROGRAM TO DROP ADDITIONAL LOAD 1728 HRS GTE REPORTS THEIR FACILITY IS ALREADY ON STAND-BY EMERGENCY GENERATORS.1731 HRS AIR PRODUCTS, GAULT, CONTACTED, SAID THEY WERE ALREADY	
469	PG&E	17:26	SHED NEWARK AREA "W-3", APPROXIMATELY 800 MW	
470	PG&E	17:29	SHED PITTSBURG AREA "R", APPROXIMATELY 290 MW	
471	PG&E	17:32	SHED ADDITIONAL FRESNO AREA, APPROXIMATELY 1,035 MW	
472	SMUD	17:35:42	HUR: 69-KV CB 6706 OPENED, CUSTOMER LOAD DROPPED	
473	SMUD	17:36:20	HED: 69-KV CB 6322 OPENED, CUSTOMER LOAD DROPPED	
474	SMUD	17:44:46	EMC: ELK FREQUENCY @ 59.46 HZ.JFK: UNIT 4KV CB 600 CLOSED, UNIT SYSNCRONIZED TO THE SYSTEM	
475	WAPA	17:45	PINNACLE PEAK-FLAGSTAFF NO. 2 345-KV LINE ENERGIZED FROM PINNACLE PEAK. PINNACLE PEAK RESTORATION DELAYED DUE TO LOSS OF SCADA CONTROL OF STATION FROM WESTERN AREA LOWER COLORADO	
476	WALC	17:45:40	PINNACLE PEAK: FLAGSTAFF-PPK #2 LINE PCB 1596 CLOSED	
477	LDWP	17:47	PDCI RESTORED 010+010	
478	WAPA	17:48	CURECANTI TERMINAL OF CURECANTI-MONTROSE 115-KV LINE CLOSE AND LINE IS IN SERVICE	
479	WAPA	17:50	GLEN CANYON-FLAGSTAFF NO. 2 345-KV LINE ENERGIZED FROM GLEN CANYON	
480	WAPA	17:50	MILAGRO UNIT 1 ON LINE, AND ORDERED TO FULL LOAD TO SUPPORT SOUTHERN SYSTEM (30 MW)	
481	LDWP	17:52	PDCI RESTORED 210+210	
482	WAUC	17:52	FLAGSTAFF 345-KV BREAKER 892 CLOSED, GLEN CANYON-FLAGSTAFF-PINNACLE PEAK NO. 2 345-KV LINE IN SERVICE. OUT 2 HOURS 3 MINUTES	
483	WAUC	17:52	GLEN CANYON UNIT NO. 4 ON LINE AT SPEED, NO LOAD	
484	WAUC	17:53	GLEN CANYON-FLAGSTAFF NO. 1 345-KV LINE ENERGIZED FROM GLEN CANYON	
485	WALC	17:53	PINNACLE PEAK-FLAGSTAFF NO. 1 345-KV LINE ENERGIZED FROM PINNACLE PEAK	
486	WALC	17:53:28	PINNACLE PEAK: FLAGSTAFF-PPK #1 LINE PCB 1092 CLOSED	
487	WAUC	17:54	(GLEN CANYON ENVIRONMENTAL RELEASE WILL BE VIOLATED DUE TO SYSTEM EMERGENCY)	
488	WAUC	17:54	FLAGSTAFF 345-KV BREAKER 396 CLOSED, GLEN CANYON-FLAGSTAFF-PINNACLE PEAK NO. 1 345-KV LINE IN SERVICE OUT 2 HOURS 5 MINUTES. GLEN CANYON PLANT ORDERED TO FULL LOAD TO ASSIST ARIZONA AND CALIFORNIA UTILITIES. (FREQUENCY AT 58 HZ IN SOUTHERN AREA.)	
489	WALC	17:54:06	PINNACLE PEAK: FLAGSTAFF-PPK #1 LINE PCB 1196 CLOSED	
490	WALC	17:56:00	PINNACLE PEAK: FLAGSTAFF-PPK #2 LINE PCB 1492 CLOSED	

AUGUST 10, 1996 WSCC DISTURBANCE–SEQUENCE OF EVENTS

EVENT #	MEMBER	TIME (PAST)	EVENT	RESTORED
491	SMUD	17:58	DECISION MADE TO ALLOW M CLELLAN TO OPERATE BEYOND EMMISSION LIMITS	
492	WAUC	18:00	GLEN CANYON UNIT NO. 1 ON LINE, UNITS NO. 3 AND 8 ARE UNAVAILABLE	
493	SDGE	18:01	NAVAL TRAINING CENTER Q RETURNS TO SERVICE	
494	LDWP	18:02	PDCI RESTORED 211+211	
495	WALC	18:02:52	PINNACLE PEAK: 230-KV BANK #1 PCB 182 RELAYED	
496	EPE	18:04	LOAD RESTORATION COMPLETE	
497	PG&E	18:18	CAPTAIN JACK-OLINDA 500-KV PARALLED AT OLINDA ESTABLISHING 500-KV TIE BETWEEN BPA AND PG&E	
498	WAUC	18:19	WILLIAMS FIELD SERVICE MILAGRO UNIT NO. 2 ON LINE, ORDERED TO FULL LOAD, TO ASSIST SOUTHERN AREA FREQUENCY	
499	IPC	18:22	ALL IDAHO POWER LOAD RESTORED TO SERVICE	
500	WAUC	18:28	GLEN CANYON UNIT NO. 2 ON LINE	
501	SCE	18:30:00.000	SCE TOU INTERRUPTABLE LOAD, MAN. SHED 56 MW	
502	WAUC	18:50	PACIFICORP REPORTS FOUR CORNERS-PINTO 345-KV LINE IN SERVICE, WSCC LOOP RESTORED ON EAST SIDE	
503	WAUC	18:55	PACIFICORP REPORT RED BUTTE-HARRY ALLEN 230-KV LINE IN SERVICE	
504	SDGE	18:58	ALL SUBSTATION LOAD RESTORED	
505	PG&E	19:11	APPROXIMATELY 1,035 MW IN FRESNO RESTORED	
506	WAUC	19:26	SHIPROCK AND WATERFLOW PHASE SHIFTERS USED TO CREATE NORTH LOOPFLOW TO UNLOAD	
507	SMUD	19:55	CONTROL AREA OK TO BEGIN LOAD RESTORATION WITHIN SCHEDULE AND GENERATION	
508	PG&E	19:56	APPROXIMATELY 80 MW IN FRESNO RESTORED.	
509	SMUD	19:59:29	LOAD RESTORATION BEGINS WITH CARMICHAEL	
510	WAUC	20:08	GLEN CANYON UNIT 8 AVAILABLE AND ON LINE	
511	PG&E	20:13	PITTSBURG AREA "R" LOAD RESTORED	
512	SMUD	20:20	DECISION MADE TO DEACTIVATE ACLM PROGRAMS.2121 HRS 33% RESIDENTIAL GROUP DEACTIVATED.2124 HRS 33% COMMERCIAL GROUP DEACTIVATED.2125 HRS ALL TEST GROUPS DEACTIVATED.2126 HRS 50% RESIDENTIAL GROUP DEACTIVATED.2128 HRS 67% GROUP DEACTIVATED.2130 HRS 100% GRO	
513	PG&E	20:29	NEWARK AREA "W-3" LOAD RESTORED	
514	WAUC	20:32	WSCC CONFERENCE CALL TO REVIEW PRESS RELEASE TO MEDIA, ALL SOUNDS OK	
515	PG&E	20:37	NEWARK AREA "W-1" LOAD RESTORED	
516	PG&E	20:42	ORDERED ALL REMAINING CUSTOMER LOAD RESTORED THAT WAS STILL OUT	
517	SMUD	20:55:10	LAST FEEDER IN SERVICE	
518	PG&E	21:54	81% OF PG&E CUSTOMERS RESTORED	
519	WAUC	22:38	GLEN CANYON SUBSTATION STATION SERVICE RESTORED TO NORMAL EXCEPT 69/25-KV YARD SUPPLIES. SHIPROCK AND WATERFLOW PHASE SHIFTERS TO NORMAL OPERATION, GLEN CANYON PHASE SHIFTER AVAILABLE AND ALTERING FLOW OFF PATH 23 NOW	
520	WAUC	0:52	8/11/96–WESTERN UPPER COLORADO "OFFICIALLY" REQUESTED APS TO ARM PACIFIC INTERTIE TRANSFER TRIPPING SCHEME	
521	WAUC	1:01	8/11/96–8APS PATH 23 EMERGENCY OVERLOAD. (GLEN CANYON KZ10A PHASE SHIFTER UNAVAILABLE DUE TO CONTINUED LOSS OF STATION AC.)	
522	WAUC	1:01	8/11/96–WSCC MESSAGE RECEIVED THAT PACIFIC INTERTIE TRANSFER TRIPPING SCHEME ARMED AT UPPER COLORADO'S REQUEST DUE TO RECENT SYSTEM DISTURBANCES. (THANK YOU!!)	

PREPARED STATEMENT OF RANDALL W. HARDY

Introduction

Chairman Doolittle and Members of the Subcommittee, I am pleased to appear before you to discuss the August 10 power outage. I am Randall W. Hardy, Administrator of the Bonneville Power Administration (Bonneville).

Today, I will discuss the reliability of the western transmission grid and Bonneville's reliability record. I will then briefly describe the events surrounding the August 10 outage, and the remedial actions taken to immediately restore the system. I will close with a summary of the institutional and technical changes we have made on our own and in conjunction with other utility groups to prevent a recurrence of the outage, and to assure dependable delivery of power as the electric utility industry is opened to competition.

Reliability and the Western Interconnected System

The Western Interconnection, which includes Alberta and British Columbia in Canada, provides power to a land area equivalent in size to more than half the contiguous land area of the United States. It serves a population of 59 million, or 24 percent of the United States' population. The grid has a larger service territory with lower population than the rest of the United States. That means it holds more circuit miles of transmission line than other parts of the United States.

Over the last four years of record, only one-third of the outages in North America have taken place among utilities belonging to the Western Systems Coordinating Council (WSCC). Of the 104 major system events in the last four years of record, 35 took place on the western grid and eight took place on Bonneville's system. Customers lost power in about half (or 16) of the events on the western grid.

Other than July 2 and August 10, there have been four outages directly related to high-voltage intertie transmission lines linking the Northwest to California in the last five years. One was caused by the Northridge earthquake in December 1994. Only the August 10 outage was related to Bonneville.

Bonneville, Pacific Gas & Electric (PG&E), Southern California Edison (SCE), the U.S. Bureau of Reclamation (Bureau), Portland General Electric (PGE), PacifiCorp, and the City of Los Angeles built the direct-current (DC) and the first two alternating-current (AC) intertie lines in the late 1960s for less than $500 million. Upgrades to the DC line and a third AC line have since been added for about $1.2 billion. The four legs of the intertie can transmit up to 7.9 million kilowatts, nearly enough power to serve the entire Los Angeles area.

Since the completion of the first intertie nearly 30 years ago, these lines have been saving southern California consumers an average of $1 million a day by taking advantage of the diversities of the electrical use and generation of the interconnected regions on the west coast. For example, the intertie transports inexpensive surplus Columbia River hydropower to California in the spring and summer, displacing electricity generated in plants fired by fossil fuels. In the first 10 years alone, the kilowatt-hours shipped south on the intertie displaced the equivalent of about 203 million barrels of oil. Power sold north on the intertie during the winter and off-peak hours helps California utilities operate powerplants at an optimum uniform level.

The exchange of electricity between the Northwest and California has also provided environmental benefits, starting with a landmark 1991 agreement. These exchanges have cut emissions in the Los Angeles Basin during the smoggiest times of the year, the equivalent of taking some 5,000 cars off the highways. In exchange, the Northwest is able to provide better flows for Columbia River salmon when the exchange power is returned from California.

Along with financial and environmental benefits, the intertie has improved reliability for interconnected systems. It enables utilities to help each other during system emergencies and to solve daily operating problems.

Including the intertie, the U.S. has invested some $4.2 billion to build the region's high-voltage transmission system. For nearly 60 years, Bonneville's charter as a Federal agency was to electrify the Northwest and make many of the investments that were necessary to create an integrated system. Bonneville provided the redundant capacity, and the computers, communications and protection controls so the Northwest power and transmission systems could be coordinated as if they were one utility, leading to economies of scale for all Northwest utilities. Bonneville offered other utilities access to the Federal transmission system without charging an interconnection fee. One third of our transmission business volume is in providing wheeling for others. Bonneville's Federal transmission system includes 15,000 circuit miles of transmission line. Bonneville provides nearly half of the electricity consumed in the Pacific Northwest and about four-fifths of the region's high voltage transmission capacity.

The provision of reliable transmission service has been a priority second only to safety at Bonneville. By developing the Pacific Northwest electric grid on a single utility basis, regional electric utilities are better able to coordinate maintenance and operation. This has given the Federal Columbia River Power System a history of exemplary reliability.

Independent reviewers have consistently given Bonneville high marks. According to a May 1996 WSCC audit, Bonneville is a well-operated system that consistently operates its system in compliance with all North American Electric Reliability Council (NERC) and WSCC reliability criteria. Despite the August outage, Bonneville made NERC's honor roll for achieving 96.8 percent compliance with its generation control reliability criteria.

Bonneville's reliability criteria have been more stringent than other entities in its service territory because Bonneville provides the backbone upon which other utilities built their systems. As measured by nationally recognized standards, Bonneville's record for outage frequency and duration has ranked better than the national average for the past decade.

This reliable and interconnected system has served the region well. It withstood cold snaps in February 1989 and December 1990 without any outages. In February 1996, Portland and parts of western Oregon and Washington were faced with the threat of massive flooding. Working with the Army Corps of Engineers, Bonneville used the grid to greatly reduce the threat by pulling back on hydro generation and pulling in other sources of power.

Bonneville continuously reassesses its systems to make improvements. Bonneville works cooperatively with other regional utilities to avoid problems before they happen. For example, Bonneville worked with four utilities in the Seattle area to mitigate a potential voltage collapse. Using system studies and growth projections, planners and engineers increased energy conservation, installed voltage support equipment and built a new substation to neutralize a situation before a problem could occur.

Bonneville has assisted Los Angeles by helping restore Sylmar after fires and an earthquake damaged the facility between 1993 and 1995. Sylmar is the southern terminus for the DC intertie. It is jointly owned by the Los Angeles Department of Water & Power (LADWP), Southern California Edison (SCE), and a number of other utilities. We provided technical and engineering expertise, project management assistance, innovative high voltage field testing expertise and spare parts for Sylmar. We sent crews, equipment, highly specialized diagnostics and high-voltage test equipment in response to emergency requests from LADWP. Despite short turn-around and hazardous site locations, work was completed without incident, and the DC intertie was restored to full capacity in a stairstep plan, months ahead of initial estimates. Support continues today with a wide range of technical exchanges, spare part supplies, and joint operations and maintenance shared among Bonneville, LADWP and SCE.

Bonneville and the utilities in Seattle and Los Angeles can sometimes be seen as competitors in the power business market. Yet in both cases, all who were involved demonstrated a true team spirit.

We need to foster that same spirit as we seek remedies for the outages we experienced this summer. The outages of July 2 and 3 that started in Idaho show that weak links, wherever they exist, can lead to complications for all who depend on the west coast transmission system. They illustrate the need for a better understanding of the voltage support problem among all utilities taking part in the western grid. Bonneville used the WSCC report on the July 2 and 3 outages to examine and improve its system. It actively implemented the recommendations from the report. For example, monitoring was instituted on a 500-kilovolt power line feeding the intertie, as well as the intertie itself, to make sure simultaneous transfers were accomplished at safe and prudent levels. Power flowing on the intertie was reduced. Bonneville and other utilities formed a group to study conditions leading to voltage collapse on the intertie. Bonneville incorporated voltage collapse scenarios into its dispatcher training. The August 10 intertie outage occurred despite restrictions set after the July 2 outage.

Events Precipitating the August 10 Outage

On August 10 we saw some of the most unusual circumstances the region has seen in two decades. High water in the Columbia River system combined with triple-digit temperatures to create unprecedented demand for inexpensive hydropower.

At the time of the disturbance, the AC intertie was carrying 4217 megawatts, well below the 4500 megawatts limit. A little over half, or about 2400 megawatts, were coming from Bonneville. One third was coming from other intertie owners, PGE and PacifiCorp. The remainder was being transferred for other Northwest utilities.

Let me correct a misunderstanding. Some have asserted that Bonneville may have not cut schedules once the initial problems started on the system in order to gain commercially. Nothing could be further from the truth. Our system dispatchers are not given commercial information on power or transmission transactions being carried out on the grid, whether on August 10 or any other time. The transmission system operators' focus is on operating the physical system for safe and reliable service. They would not and could not have operated on August 10 to maximize Bonneville's commercial gain at the expense of reliability, because our operators' responsibility is only to dispatch. Information about commercial operations reside with scheduling, a separate function that does not control transmission system operations.

At 2:06 p.m., hot weather caused Bonneville's Big Eddy-Ostrander 500-kilovolt line to sag into a tree. Bonneville immediately notified PGE through the normal channels. About 45 minutes later, the same happened to the John Day-Marion 500-kilovolt line. The outage of these two east-west lines was not considered critical at the time because the lines were carrying light loads. About an hour later, the heavily loaded Allston-Keeler 500-kilovolt line sagged into a tree and relayed. Notification of this line outage was transmitted to PG&E by Bonneville over the new WSCC inter-utility data computer system. These events resulted in a loss of voltage support, particularly in North-Central Oregon, at the head of the intertie. Initially generation at McNary Dam sought to offset this problem by increasing voltage support. But within five minutes, all generating units at the Corps of Engineers' (Corps) McNary Dam shut down, dropping nearly 700 megawatts in 70 seconds. Growing oscillations then caused the tripping of the AC intertie lines. It is critical to understand that while the initiating event for both the August 10 and July 2 outages was transmission line contact with trees, it appears that the more substantive problem is the lack of voltage support, due to the configuration of the power system.

In the following days, the loss of generating units due to the outage and record-setting loads in California created an emergency situation. In response to the emergency, California Governor Wilson directed state agencies to reduce energy use. PG&E employed all generators available, curtailed power to large industries and farms, and called for voluntary restrictions at homes and businesses.

Bonneville worked with the Corps, the National Marine Fisheries Service and others to gain a temporary waiver of spill requirements for endangered salmon at The Dalles Dam. A run of endangered fall Chinook salmon was migrating downstream. The region's dams had heavy demands to meet Northwest power needs during the heat wave. Bonneville was able to gain the support and cooperation needed to support a declaration of emergency for California, shift the timing as well as volume of spills for endangered salmon, and request and obtain increased power generation at The Dalles Dam by 700 megawatts to provide stable power down the intertie. The Dalles was chosen because it is nearest the northern end of the intertie and would reduce stress on the transmission system. This agreement meant generating more power at four other dams, releasing more water for salmon right after the emergency and extending the length of time water would be spilled for fish - all at a cost of more than $400,000.

Without these quick actions, portions of California faced the threat of additional widespread power outages with the potential to threaten the health and safety of millions of customers. PG&E and the California Public Utility Commission expressed great appreciation for these efforts. Western utilities and suppliers have a responsibility to each other as partners in an interconnected grid. Each system should do all it can minimize the impacts of separation and take actions to ensure the fastest possible restoration.

Immediately after the outage occurred, Bonneville began working with other utilities to restore the system. As a precaution, the intertie was limited to only two-thirds of its scheduling capacity. Bonneville set interim operating procedures for the intertie with PG&E and SCE. Together, we determined what outages should be reported, how quickly they should be reported, how to ensure safe operating conditions and limits, and how to resolve issues.

Along with other Northwest utilities, we set conservative operating limits on transmission paths along the western corridor. Crews installed additional remedial action schemes on the AC intertie at the California-Oregon border to activate voltage support more quickly. To date, Bonneville has foregone about $2 million in transmission revenues due to these restrictions on the intertie.

We have reviewed our vegetation management program and developed a plan for improvement. We are currently implementing the plan's 46 recommendations which will improve all aspects of our vegetation management from planning to implementation.

Bonneville immediately expanded its vegetation management program. Within days, more than 2,700 trees were pruned or cut. Brush was removed from about 1,200 acres. Nearly 2,300 miles of transmission line were patrolled by foot and by air. Over the past two years, budgets to control vegetation under power lines increased from $2.5 million to $3 million. Budgets will increase again, by another $1.5 million over the next three years.

The Corps and Bonneville quickly reviewed equipment at McNary Dam. Bonneville transmission system operators factored in limitations for the Corps' generating plants on the mainstem of the Columbia to eliminate voltage stability risks. Dispatchers heightened their awareness of system vulnerabilities and improved communications with neighboring utilities.

Changes and Innovations to Safeguard the Transmission System

In the three months since the outage, Bonneville has put in motion a number of technical and institutional changes to further strengthen the system.

These changes both fortify the system against such unusual events as the conditions experienced on August 10, and safeguard against new demands placed on the grid by changes in the industry and new constraints on Columbia River hydro generation. We have ten initiatives underway to prevent or limit system disturbances and respond more quickly to potential emergencies.

Fourteen industry experts are taking part in a "blue ribbon panel" to review a system-wide study of voltage support on the Bonneville transmission grid. The study is a collaboration between Bonneville and other west coast utilities to identify any deficiencies in voltage support and determine corrective measures. It will review the power system, including generators and generator controls, for voltage and dynamic stability. Nominations for the panel came from NERC, WSCC, EPRI and several western utilities. The panel will receive study results and recommendations on November 20, provide an evaluation by December 6, and conclude its work by January 31, 1997.

Effective October 1, Bonneville combined dispatchers, system operation and technical staff to create a single transmission planning and operations staff. This will improve coordination between short term or operational study efforts, long term or planning studies, and the real-time dispatch of the power system. We also integrated natural resource and realty specialists with transmission line maintenance staff. This will strengthen right-of-way maintenance and vegetation management. In addition, responsibility for overall right-of-way maintenance has been specifically assigned to transmission line maintenance foremen.

Our vice presidents in transmission are meeting weekly with me, the Deputy Administrator, Chief Operating Officer, senior transmission managers, and manager for Federal Hydro Projects to receive briefings and set direction on reliability issues.

We plan to expand the wide-area measurement system (WAMS). This technology was developed in cooperation between Bonneville, the Department of Energy, Western Area Power Administration, the Bureau of Reclamation, the Pacific Northwest National Laboratory, and the Electric Power Research Institute (EPRI). It can bring us the measured information needed to model and control the power system's dynamic performance. It uses global positioning satellites to precisely synchronize the measurement of power system quantities over very large distances. WAMS was instrumental in diagnosing the August 10 disturbance. We need to add other areas of the western system to WAMS to gain the breadth of view needed to improve system reliability.

We are also improving power system operational and dispatcher screening tools for assessing system capabilities and limitations, which should reduce the potential for outages. We are finding ways to better identify and plan for a variety of load, generation and transfer conditions.

We have added new scenarios, system problems, resolution techniques and emergency coordination actions to dispatcher training. Dispatchers have long had training on voltage collapse scenarios; now they have a simulation of the August 10 disturbance. We will clarify dispatching procedures to facilitate emergency schedule readjustments and coordination among control centers. Operators are now more sensitive to voltage fluctuations and what they need to do to respond.

We worked with the Corps to modify exciter controls on the generators at McNary Dam. Technical experts from the WSCC agree that the modifications are appropriate to ensure the generators do not trip during disturbances, except to prevent damage to equipment. Tests confirm the results. Consistent with WSCC recommendations, we have taken immediate steps to improve communication and coordination with the Corps, instigating joint meetings every two weeks on system design and planning. We will work with groups who own other power generators to retune power system stabilizers as a way to offset undamped system oscillations. We will work with the other utilities who own the DC intertie to reactivate modulators that can help dampen system oscillations. We will identify and put in place other automatic controls to prevent loss of the intertie.

Operators automatically will notify PG&E and other WSCC utilities of all outages, both planned and unplanned, on 500-kilovolt and key 230-kilovolt lines. Dispatchers will call if any outage would reduce the operating capacity of the intertie. They will warn PG&E dispatchers about major storms moving through the Northwest, with a notice if the storm forced lines out of service.

Overall policy recommendations

Bonneville is taking actions to implement all the recommendations in the WSCC preliminary report applicable to Bonneville, as well as taking actions that go beyond the recommendations in the report. We believe these actions will significantly reduce, but not eliminate, the potential for another separation of the Northwest-Southwest interties. In fact, it was recognized at the time the interties were constructed that the potential for separation cannot be eliminated. As the WSCC report notes, there are circumstances in the Southwest which may have adversely affected the extent of the outage. The WSCC report identifies the need for additional study and action

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to resolve these issues. Because we cannot guarantee that another intertie separation will not occur in the future, we urge the Southwest parties to implement the recommendations of the WSCC report in order to minimize the impact of any future disturbance.

Meanwhile, changes in the industry are placing new demands on the transmission grid. Open transmission access is producing new or accentuated flow patterns across the entire transmission network. While complying with deregulation initiatives to separate power marketing from transmission, Bonneville is encouraging all utilities to:

- Require all control area operators to join NERC and regional reliability councils.
- Better coordinate generation and transmission operations where critical for ensuring system reliability.
- Establish criteria for new power generators to make sure they meet the reliability needs of the transmission system.
- Establish standards for formal certification for transmission and generator control and protection equipment to make sure equipment is set and operated according to WSCC guidelines, and is depicted correctly in power system network studies.
- Investigate the formation of strong regional grid operators that have adequate responsibility and authority for transmission reliability. Having one grid operator increases the region's ability to overview the entire transmission system and its interconnections efficiently. Bonneville believes that this independent grid operator (IGO) should not only plan, price and schedule, it should also direct transmission control and dispatch, with incentives for both efficiency and reliability. A grid operator must be alert to the types of changes deregulation will bring. It must be responsive to the needs of the public it serves, and operate for

the common good. A Northwest IGO must be a reliable partner for California.

Conclusion

Bonneville is taking actions to implement all the recommendations in the WSCC preliminary report applicable to Bonneville, as well as taking actions that go beyond the recommendations in the report. We believe these actions will significantly reduce, but not eliminate, the potential for another separation of the Northwest-Southwest interties. We have been intensively seeking out the causes of the problem and believe we are on a path to resolving the issues which are at the core of this outage.

As events move forward, Bonneville will do everything in its power to identify reliability issues and take corrective actions, and to work with other utilities to restore confidence in the west coast transmission system. We believe vigilance in these matters will ensure that we will deliver safe and reliable transmission service well into the future as we have in the past.

Mr. Chairman, this concludes my statement. I would be pleased to address any questions from the Committee.

PREPARED STATEMENT OF JOHN E. VELEHRADSKY

Mr. Chairman and distinguished members of the Subcommittee, I am John Velehradsky, Director of Engineering and Technical Services, North Pacific Division, U.S. Army Corps of Engineers. I am pleased to be here today representing Mr. Martin Lancaster, the Assistant Secretary of Army for Civil Works. In my current position, I am responsible for technical direction of the planning, design, construction, operations, readiness and real estate activities associated with Corps of Engineers water resource management activities in the Columbia River basin. In my testimony, I will briefly describe the Corps hydroelectric generation facilities in the Northwest and how they are managed. I will address the outage of August 10,1996, as it relates to the Corps operations and management. I will also explain the actions that the Corps is taking since the incident to help this multi-jurisdictional power system respond to such abnormal occurrences.

The Corps of Engineers operates and maintains 21 hydroelectric projects in the Western Systems Coordinating Council (WSCC) service area. The WSCC is an association of 91 power systems in 14 western States, two Canadian Provinces, and part of one Mexican State that promotes electric system reliability and provides a forum for coordinating the operating and planning activities of its members. The maximum generation capacity at the 21 Corps dams is 12,937 Megawatts which represents approximately 24.5% of the hydropower capacity in the Northwest. One of these 21 Corps projects is at the McNary Dam located about 292 miles upstream from the mouth of the Columbia River and near Umatilla, Oregon. As a result of the voltage depression in the system on August 10, the generators at McNary tripped off in order to protect the equipment.

Power generated at the Corps projects is marketed and transmitted to customers by another Federal agency, the Bonneville Power Administration. Many factors affect how these dams and reservoirs are managed to produce power. The Columbia River Treaty regulates how water and power are traded between the U.S. and Canada, and the Pacific Northwest Coordination Agreement specifies how power is produced and shared among regional utilities. There are also many non-power uses for the Columbia River that affect how the Corps facilities are operated. The dams and reservoirs that the Corps operates are multipurpose projects that balance the demand for hydropower with other legitimate uses for the water including navigation, flood control, water supply, recreation, and fish passage. All of these factors are considered in the development of operation plans for the reservoirs in the Columbia River system.

The Columbia River and its tributaries are home to salmon and sturgeon that annually migrate the rivers moving past the series of dams that have been constructed in their path. During critical fish passage periods, from April through August, water control and hydropower operations are managed to avoid jeopardy to salmon and sturgeon that are protected under the Endangered Species Act, and to mitigate impacts to other important fish and wildlife resources. To facilitate fish migration, extra releases of water are allowed to bypass the generators at carefully timed intervals. This activity requires close coordination among the Corps water managers, Bonneville Power Administration's dispatchers, and power plant operators.

Following the power disturbance that occurred on August 10, 1996, the WSCC released findings concerning the July 2-3 and August 10, 1996, disturbances. The Council's findings as they relate to Corps operations are paraphrased as follows:

The power system experienced depressed transmission system voltage prior to McNary tripping;

The McNary generators tripped off sooner than would have been expected based on power system studies.

The level of generator voltage (reactive) support available in the Hanford area was inadequate to prevent system collapse; and

The North American Electric Reliability Council recommendations in "Survey of Voltage Collapse Phenomena" need to be implemented.

After this incident, the Corps performed its own assessment of the performance of the generation equipment. We found that the McNary units performed as originally commissioned by the manufacturer. During the period of depressed transmission system voltage just prior to the system shutting down, McNary provided voltage support above machine design capacity for about five minutes. Eventually, however, this was insufficient to overcome the losses elsewhere in the system and the generators tripped off.

The 13 McNary generating units shut down in a self-protective mode in response to the major voltage depressions that were occurring in the transmission lines. The automatic tripping of the McNary generators is a safety measure that protects the equipment during such abnormal fluctuations in voltage.

While we found that equipment performance was generally consistent with our expectations, we also learned that the power system voltage in the McNary area was depressed below any level anticipated placing a higher than expected demand on the McNary units. As a result, the McNary units tripped off sooner than we had expected. We do not know that, had the units stayed on line a few minutes longer, the ultimate result of the incident would have been any different.

Although the tripping of the McNary units was only one of the problems associated with the outage, we have identified a few improvements we can make that will help us respond if we are faced with a similar event in the future. These measures respond to the WSCC's findings and recommendations and our program for improving the availability of generation and equipment reliability. We are making some adjustments to the McNary and other units that will improve their response to an impending voltage collapse in the system. We are improving coordination among Bonneville Power Administration, WSCC, and the Corps to assure that everyone involved is aware of the capability of the Corps equipment in operation.

These measures that the Corps is taking will not by themselves prevent a future incident like the one we just experienced. But they will assure that the Corps operated and maintained facilities are more responsive to the power system's future requirements. Together with steps that can be taken by other players in this power network, the whole system will be more reliable.

Mr. Chairman, this completes my testimony. I would be happy to respond to questions.

PREPARED STATEMENT OF P. GREGORY CONLON

RECOMMENDATIONS FOR IMPROVING ELECTRIC SYSTEM RELIABILITY IN THE WEST

Statement of the Hon. P. Gregory Conlon, President, California Public Utilities Commission before the Water and Power Resources Subcommittee of the U.S. House of Representatives Committee on Resources concerning "Issues and Recommendations Concerning the August 10, 1996 Bonneville/Western U.S. Power Outage."

Los Angeles, California
November 7, 1996

As recently documented in the Western Systems Coordinating Council's (WSCC) Report of October 18, 1996, at 3:48 p.m. on Saturday, August 10, 1996, in the western United States, Canada, and Mexico, 7.5 million customers lost their electric service for up to nine hours. As explained in the WSCC Report, a combination of problems, not just a single incident, precipitated the cascading grid outage. In the hours before the disturbance, three 500-kV lines were forced out of service. Two of the outages (Big Eddy-Ostrander, John Day-Marion) were caused by flashovers (trees coming into contact with power lines as the lines sagged under heavy transfers of power and over 100-degree ambient temperatures); the other outage (Marion-Lane) resulted from an out-of-service circuit breaker. These substantial events occurred when the Allston-Rainer line was out-of-service due to degraded capability of line hardware. And more generally other lines and equipment were out-of-service or at reduced capability due to maintenance activity. At the same time, the Dalles hydroelectric facility was only operating five of 22 generators due to fish mitigation requirements.

Although operating near its limits, the system performed adequately up to this point. Then came the proverbial straw that broke the camel's back, when Bonneville Power Administration (BPA) evidently was operating in violation of WSCC reliability criteria and a single contingency triggered the subsequent cascading outage. (WSCC Report, p. 8, Conclusion 1.)

At 3:42 p.m., the heavily loaded Keelor-Allston 500-kV line sagged too close to a tree and flashed over. From this point additional lines were overloaded. The outage might have been mitigated if not for the failure of other equipment. At 3:47 p.m. the St. Johns-Merwin line tripped due to a faulty relay, contributing to the loading of other lines. Another flashover (the fifth that day) caused an outage and loss of 207 MW of generation from the Swift plant, increasing the need for voltage support from the McNary generating units which were already at their maximum. The McNary units began tripping (due to excitation equipment problems), and voltage oscillations began. These oscillations were a major factor in the Pacific Intertie separation and subsequent islanding of the WSCC system.

Although no firm estimate exists of the total cost of the outage, it is not improbable that it was on the order of tens-of-millions of dollars, both in lost revenue to electric utilities and, more importantly, in real costs associated with the loss of service and the attendant consequences including closure of commercial establishments, congestion and accidents on roadways, and loss of production capabilities. Consequences ranged from lost sales to the increased risk of injury and death.

Following the outage, the Pacific Intertie's North to South rating was lowered from 4,750 MW to 3,200 MW. The WSCC is currently reviewing methods for reliably operating the Intertie at higher limits. This issue needs to be resolved in a timely manner before next spring. California has suffered already from not being able to draw fully on Pacific Northwest imports during the late part of this past summer. The situation needs to be rectified before the spring of 1997.

The WSSC should be thanked for providing an excellent report on the August 10, 1996 outage. The WSCC and its committees are continuing that investigation and we look forward to additional information and conclusions. The WSCC Report shows that much has been done to ensure the reliability of the interconnected western grid. But the outage -- and what we have learned from it -- is evidence of the remaining work that needs to be done to avoid recurrence of cascading power outages on the western grid.

The WSCC Report summarizes by stating, "...the disturbance could have been avoided, in all likelihood, if contingency plans had been adopted to mitigate the effects of the Keeler-Allston 500-kV line outage. Inadequate tree-trimming practices, operating studies, and instructions to dispatchers also played a significant role in the disturbance." (WSCC Report, p. 6). Probably adding to the problem was the failure of critical equipment (relays, conductor hardware, generation control) that also played a major role in both the outage and the time needed to restore service. The WSCC Report also found that some of the system was operating in suboptimal condition. For example, some power system stabilizers were not operating due to plant control problems (WSCC Report, p. 32).

The WSCC Report also concluded:

> "The July 2 and August 10 disturbances emphasized the need for timeliness in the disturbance report recommendation resolution process. Examples of recommendations made as a result of previous disturbances that continue to be factors in more recent disturbances include the recommendations relating to controlled islanding, criteria for multiple contingencies, criteria for relay failures, and coordination of underfrequency load shedding." (WSCC Report, p. 27, Conclusion 32.)

This particular conclusion highlights the need for enforceable reliability standards. We cannot afford a system where problems, once identified, continue to exist, creating costly outage after outage. The reliability of the transmission system is only as strong as its weakest link.

It is clear that the western grid is very robust and can tolerate a wide range of significant disturbances. It is also clear that the grid is vulnerable. On August 10th, after a series of transmission outages and generation failures, the system collapsed. Existing mitigation measures and protective equipment failed to stem the collapse of the system. Reliability must be increased through a variety of steps recommended below.

Analysis of the August 10th disturbance is ongoing. However, we can draw the following conclusions from the WSCC's recent report on the outage:

First, maintenance of the existing grid is of extreme importance and has not been adequately addressed by many of the transmission-owning utilities. The report details the many instances of inadequate tree-trimming practices and equipment failure.

Second, operating standards evidently are not adequate. The WSCC Report notes that BPA had been "unknowingly" operating in violation of the WSCC Minimum Operating Reliability Criteria before the August 10th outage. (WSCC Report, p. 4.) For example, there was a July 13, 1996, incident that included a flashover to a tree on the Pearl-Keeler 500-kV line, an incident that also had included failure on the Allston-St.Helens 115-kV Line due to the failure of degraded conductor hardware. Although the incident did not lead to a cascading outage "... it should have served as a warning prior to the August 10 outage and led to further technical analysis" (WSCC Report, p. 4).

Third, communication and coordination both between control area operators and within control areas were apparently inadequate. (WSCC Report, p. 14, Conclusion 8, p. 20, Conclusion 17, and p. 25, Conclusion 30.) Information on the status of critical elements within the western grid must be communicated to all control area operators immediately following an outage and back-up communications systems must be set up to allow critical information to continue to be transferred in emergency conditions.

BPA did not report the three 500-kV line outages experienced in the one-and-a-half hours prior to the disturbance to other control area operators (WSCC Report, p. 14). Such information, if communicated to other control area operators, may have allowed them to take mitigating actions that would have prevented the problem from getting out of hand.

There is evidence as well to suggest that communication and coordination <u>within</u> control areas could be improved. Rapid and effective responses from various generating entities is especially critical in situations like the August 10th disturbance. It is hoped that there will be enhanced communication and coordination between BPA (the control area operator) and the generator operators (Corp of Engineers and the Bureau of Reclamation). Also, in many cases, utility data gathering systems and communication facilities with generation and transmission operators were disrupted and could not be used. (WSCC Report, p. 24, Conclusion 28.)

Based on these findings, I make the following recommendations to maintain adequate reliability in the future and avoid repetition of cascading events like the ones precipitating the August 10th outage.

RECOMMENDATIONS:

1. Inspection, maintenance, and testing of transmission facilities should be strengthened. In California, I am personally recommending the implementation of periodic inspections by Commission staff of the 230-kV and 500-kV system and reviews of utility line-patrolling and tree-trimming records.

2. Operating procedures and training of operating personnel need to be reviewed and strengthened. Operators need to know how to recognize critical conditions and what specific steps to take to preclude cascading outages. Systematic risk management must occur. Circumstances involving low probability of occurrence nevertheless need to be identified if there is a risk of significant regional consequences.

3. Adequate communication procedures and redundant systems must be in place to assure communication between control area operators and entities within and outside of their control area. Information about the real time operation of the grid must be accessible. This may require additional dynamic monitoring devices. Procedures must be adopted that clearly identify what information must be shared and the method of transferring that information.

4. I believe that system reliability requires enforceable standards and rules. As the electric utilities industry becomes more competitive, the need for enforceable standards will increase. To ensure compliance, violation of standards should trigger sanctions that outweigh any cost savings that can be gained by avoiding implementation of necessary standards.

This was the second major outage due to cascading effects of the interconnected grid to occur this past summer. A third widespread outage may have been narrowly averted on July 3rd, 1996, when operators at Idaho Power Company shed approximately 600 MW of their own load when flashover occurred on the same transmission line as the previous day. This action was taken in response to problems that occurred on other systems.

As competition increases, we cannot continue to count on voluntary actions by utilities in response to disturbances caused by third parties if those actions have adverse financial impacts on their shareholders or impact provision of service to their customers. Regional, mandatory standards should be established. There is a clear need to create mechanisms to impose penalties on entities that fail to operate within established standards. Violation of those standards should be subjected to enforceable sanctions. Effective penalties would need to exceed the cost of failure of compliance with the standards, or may otherwise be considered part of the cost of doing business. Users of the grid would need to be in compliance or face the consequences when they are not.

State regulatory agencies have an important role to play. State commissions perform environmental review and set line construction standards, perform inspections, and enforce safety requirements. Reliability standards within each control area and utility are inexorably tied to inter-control area standards, such as those set by the WSCC. Each of these elements is intrinsically related to reliability and the physical transmission system. Tree-trimming, for example, involves reliability and safety concerns that cannot be separated. Flashovers affect both the reliability of the grid and public safety. We cannot afford to wait for yet another failure before we move to a system of mandatory compliance with regional reliability standards. As you know, California is a "three strikes and you're out" state. I firmly believe that we cannot afford another major outage, the third strike.

State agencies acting in coordination with other states that are imposing standardized requirements, can inspect and test both the physical system (tree trimming, relays, maintenance) and also verify that grid users adhere to uniform operational and communication procedures.

I personally would recommend a region-wide Independent System Operator (ISO) as a natural vehicle for maintaining system reliability and setting and enforcing regional reliability standards. Perhaps in the not too distant future we may be operating the western grid under one ISO, in which case the entire responsibility for the grid operation and reliability will rest with one entity. In California, the recently enacted Assembly Bill 1890 provides that the ISO in California, once established, will play an integral part in creating and adopting reliability standards. As ISOs develop and assume control area operator functions, the number of control area operators will decrease, consolidating responsibility for system reliability. Eventually the entire western grid should be controlled by one ISO.

While ISOs are developing, interim measures are necessary to enforce region-wide standards. The California Legislature has suggested the use of an interstate compact, where California will join other western states in an agreement requiring the region's electric utilities, both public and investor-owned, to adhere to enforceable standards and protocols to protect the reliability of the region's electric supply.[1] An interstate compact may

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1. On September 23, 1996, Governor Wilson signed Assembly Bill 1890. A.B. 1890 addressed regional reliability concerns by including Section 359:

> "It is the intent of the Legislature that California enter into a compact with western region states. That compact should require the publicly and investor-owned utilities located in those states that sell energy to California retail customers, to adhere to enforceable standards and protocols to protect the reliability of the interconnected regional transmission and distribution systems."

require congressional approval as stipulated by Article 1, Section 10 of the United States Constitution. Because the participation of Canadian and Mexican utilities are desirable, eventually an international treaty may be necessary as well.

I have recently sent a letter to members of the Committee on Regional Power Cooperation (copy attached), asking them if they would work with California in establishing regional reliability standards through entering into a regional compact or some other vehicle for cooperation. Another possibility would be to coordinate the actions of the western states, Canadian, and Mexican regulatory agencies in an effort to enforce universally applied standards and protocols. Each state or province, on its own, would require compliance with uniform standards (such as those adopted by WSCC or NERC), and implement its own program for enforcing those standards. Models for this type of action include the Western Interstate Energy Board or coordination of ratemaking for multistate utilities.

An additional alternative would be to utilize the existing regional reliability council (WSCC), to functionally perform as an entity that both sets and enforces regional standards. For this to occur, at least four changes would need to be made in the existing WSCC structure:

1. Mandatory membership of all grid owners in the WSCC would need to be implemented;

2. Participation of representatives from state and provincial regulatory agencies on an ex-officio basis at both WSCC and NERC would have to be provided. Because of the limited budgets of many of the agencies, membership should be provided without cost. The WSCC and NERC should pro-actively seek regulatory agency participation at all levels of the WSCC and NERC organizations. The WSCC recently has included the Utility Commissions of California, Oregon and New Mexico to become ex-officio members of the WSCC;

3. The WSCC would need to implement enforceable standards that carry contractually required sanctions for non-compliance. Those sanctions, like state-imposed sanctions, would have to exceed the cost of avoiding the standards to be effective. Methods to verify compliance would have to be implemented; and

4. The WSCC would need to increase its staff to test and evaluate grid users' compliance with the standards.

Finally, market mechanisms may provide opportunities to efficiently increase grid reliability. One such mechanism is to unbundle ancillary services, specifically identifying voltage support as a separately priced service. There are many ways that voltage support can be provided: additional generators, capacitors, large synchronized electrical motors and de-watered hydroelectric generation. Separate pricing of voltage support should encourage exploration of cost-effective alternative methods for providing this important reliability service.

Moreover, once prices for unbundled services are identified, customers can choose service on an interruptible basis, knowing the market value of their choice.

The system today primarily uses generation as the sole mechanism to provide for voltage support. Future market-driven options, on the other hand, can help ensure a more versatile and reliable grid with reliability functions being provided by customers as well as providers.

Reliability is the responsibility of all, grid users, utilities, control area operators, reliability councils, state regulatory agencies, federal agencies, and even customers (as we move to an unbundled electric market). As competition increases, it will provide both challenges and opportunities. We look forward to working with each of these groups to ensure an efficient and reliable electric system.

Attachment

Public Utilities Commission
STATE OF CALIFORNIA
505 VAN NESS AVENUE
SAN FRANCISCO, CALIFORNIA 94102

P. Gregory Conlon
PRESIDENT

TEL: (415) 703-2440
FAX: (415) 703-2532

October 17, 1996

Dear Fellow Members of the Committee on Regional Power Cooperation:

Assembly Bill (AB)1890, just signed by Governor Wilson, declares the Legislature's intent that California join the other western states in an interstate compact requiring the region's electric utilities, both public- and investor-owned, to adhere to enforceable standards and protocols to protect the reliability of the region's electric supply. Article 1, Section 10 of the US Constitution requires congressional approval of any interstate compacts. Thus, any compact that we develop may require federal legislation. Two months ago, the California Public Utilities Commission, with commissioners from several other states also attending, held an informal inquiry into the August 10 blackout. We were all very concerned about the ability of the current voluntary system to maintain the reliability of the western region's electric grid.

We are therefore inviting you to work together with us to develop solutions to any reliability problems that may exist. This work is trans-national, insofar as our electric systems are already substantially interconnected with those in Canada and Mexico. By committing itself to an inter-state compact, California has committed itself to a major and historic task, which will require sustained and coordinated effort by not only all of the western states, but Canada and Mexico as well. Indeed, the ultimate results of our efforts may well be an international treaty on regional electric coordination.

Our Commission has already begun the dialogue necessary to pursue these regional goals. Commissioner Fessler has raised the issue in Mexico with Energy Secretary Heroles and the members of Mexico's Comision Reguladora Energia, as well as with Mr. Roland Prittle, Chairman of the Canadian National Energy Board. Canadian provinces are active in WRTA, and conversations with Canadian officials should be pursued actively at both the provincial and federal levels. It was the suggestion of the chairs of the State Commissions of Arizona, New Mexico and California that WRTA actively seek out Mexican participation. At the same time as these initiatives have been pursued, we have begun to contact other state agencies and legislative staff within California.

We also believe that there are a number of other steps that we could take to improve reliability, short of the adoption of an interstate compact or international treaty. One option may be to establish a group similar to the regional operating committee that currently oversees US West's telecommunications operations in the Western United States. Another option may be the adoption of a uniform electric reliability code, adopted by each jurisdiction. For example, that code might require conformance to standards set by the Western Systems Coordinating Council (WSCC).

In this connection, we note that AB 1890 authorizes the Independent System Operator to seek authority from the Federal Energy Regulatory Commission to penalize transmission owners or operators that violate operational rules. Further, our Commission has already initiated a proceeding to set and enforce reliability standards for distribution systems and tree-trimming practices for some control areas. We already have set enforceable measures for system-wide reliability within some investor-owned control areas.

Finally, as we work to make our system enforceable we must continue to make improvements in our current voluntary system. We are heartened by WSCC 's plans to appoint security coordinators, to provide them with information on the western system in real time, and to authorize them to order emergency responses by member utilities. We do wonder whether this effort will receive adequate resources to function fully, or whether additional effort would yield an additional level of security. In any case, appointing security coordinators alone may not be enough to prevent outages like the one many of us experienced August 10, which was caused in large part by multiple transmission line failures due in turn to inadequate tree trimming. Although WSCC has called upon members to review their tree-trimming practices, we are not sure that this is enough to guarantee a coordinated approach throughout the West; as the recent outages have shown, the system is no stronger than its weakest links.

These observations suggest that we can improve reliability by taking systematic steps. First, our region, including Canadian provinces and Mexican states, must evaluate the risks to the electricity system in a systematic way, considering that various combinations of extreme weather and other conditions, however unlikely, sometimes do occur. The WSCC and its member utilities have done considerable work in this area; but we wonder whether increased effort and international cooperation, along with the increased computing power now available, might yield additional insights. Second, we need to adopt cost-effective operation and maintenance standards that deal with these risks. Finally, we need to make sure that the region's institutions have the resources and mandates to find and publicize failure to follow these standards.

Pursuing such voluntary measures will not only improve the reliability of the system while we work toward an interstate compact, but also make that compact far more efficient once we achieve it. We hope you find this prospect as exciting as we do.

Given the importance and interest in system reliability you may wish to raise these issues with your Governor's Office when you return from this conference. This issue may also benefit from discussion at the next Governor's conference.

Sincerely,

P. Gregory Conlon

P. Gregory Conlon
President

Daniel Wm. Fessler

Daniel Wm. Fessler
Coordinating Commissioner on
Electric Restructuring

FOLLOW-UP ADDRESS/OUTLINE PAGE

1. P. Gregory Conlon, President

2. California Public Utilities Commission
   505 Van Ness Avenue, Room 5200
   San Francisco, CA 94102

3. (415) 703-1175 (Telephone # of John L. Scadding, Advisor)

4. Topical Outline:

   I. What happened on August 10, 1996
      A. Flashovers
      B. Hardware failure
      C. Operational Errors

   II. It could have been avoided
      A. Contingency plans
      B. Adequate maintenance

   III. We have seen these problems in earlier disturbances
      A. They have not been resolved
      B. Enforcement needed

   IV. Four recommendations for increased reliability
      A. Increased maintenance
      B. Better operating standards
      C. Better communications and coordination
      D. Standards must be enforceable

   V. Methods for implementing enforceability
      A. Regional ISO
      B. Interstate compact
      C. Modified reliability council
      D. Market forces

PREPARED STATEMENT OF RENZ D. JENNINGS

Testimony before the Water and Power Resources Subcommittee of the
U. S. House of Representatives Committee on Resources
November 7, 1996
Page 1

First let me say that I approach this hearing with a certain sense of humility in trying to suggest improvements to a system that is so complex. A lot of people are doing a lot of things to resolve problems identified this summer. I am not an engineer or electric reliability expert, but I hope to bring a new perspective to the discussions of this summer's outages.

The two major western power outages this summer on July 2-3,1996 and August 10, 1996 have left us with an interesting risk management problem. We won't be able to completely eliminate the outages, but we can develop reasonable risk management strategies that will reduce the possibility and impacts of future outages. In order to address this risk management problem we need to look at six aspects. They are:

- The need for more and better quality information
- The need for credible commitments to reliability
- The need for better communication among utilities and others
- The need for a clear delineation of responsibilities
- The need to develop better damage control
- The need for participation by all appropriate parties in the development of risk management solutions.

Let me take each of these aspects and discuss them in depth.

First, the need for more information relates to our need to better understand the western integrated electric grid under a wide variety of possible operating conditions. Rather than merely looking at likely single contingency scenarios, known as N-1 scenarios, we need to have WSCC and utilities look at models of multiple contingencies, known as N-2, N-3, etc.; scenarios.

Second, we need to elicit credible commitments to reliability from **all** participants in the interconnected grid. This should start with mandatory membership in WSCC or, at least, mandatory requirements to meet WSCC's minimum reliability standards. A performance bond could be required as a sign of credible commitment and could be attached in case of failure to comply with reliability criteria.

Since the two major western power outages this summer in July and August, we have heard over and over again that the safeguards built into the western interconnected grid worked as designed. The system islanded, power plants were tripped to prevent equipment damage, and loads were shed to help stabilize the system, thereby avoiding a complete shutdown of all western power generation. Yes, it appears that the protective mechanisms worked after an irreversible problem started the blackout. While it is important to improve the system in ways that will limit the damage from a system outage, it is far more important to take steps to avoid the conditions which led to the start of the outage.

This brings me to a major concern that we in Arizona have. If, in fact, the NERC and WSCC criteria and requirements are appropriate, there still is a major problem ensuring that those standards are enforced. Unless there are some credible penalties or sanctions applied to those who fail to meet the standards or shirk their responsibilities, we will have a reliability system that works in theory, but not in fact. Enforcement and penalties can be handled in a number of ways. First, WSCC and other regional reliability councils could take on the responsibility of enforcement and penalties. Second, the federal government could take the responsibility. Finally, the various state PUCs could take on the enforcement and penalty responsibility; however, achieving uniformity among states might prove difficult.

My preference would be to have WSCC perform this function. WSCC would monitor and measure compliance. Although NERC has the national responsibility for reliability, it is not staffed or prepared to take on an enforcement mission. Concerted State action might be much more difficult than having one entity in each region (WSCC and the other regional reliability councils) handle the enforcement of standards.

Effective enforcement would only be possible if mandatory membership were made possible by FERC ruling or by federal legislation. States could require membership, but this would only work if each and every state made membership a requirement.

Third, we need better communications among the participants in the western grid. It is very likely that if we had a better inter-utility communication system on August 10 that the outage might have been avoided, or at least it might have given enough warning so that the resulting impact might have been reduced. We need a real-time disturbance alert mechanism so that operators on the integrated system can get early warning of problems which may affect their system operation.

Fourth, we need to ensure that, as we move to a more competitive electricity market, there is a clear delineation of reliability responsibilities through either market mechanisms, through contracts, through state or federal regulations, through Independent System Operator mechanisms, or through WSCC requirements.

Fifth, we need to develop better damage control mechanisms. These could include better islanding methods. Arizona is a relatively small state, in terms of population and power usage, compared to our neighbor to the West. So, to the extent that California utilities and northwest utilities ignore potential problems on the western interconnected grid, the resulting outages will probably continue to have a major negative impact on Arizona's electric system. Whatever happens in the California power markets has a significant impact on all of the adjoining states. Since California is going to lead western states in the move toward restructuring and competition in the electric utility system starting in 1998, we hope that adequate care will be taken to ensure that all competitors in the California market meet reliability standards -- along with a fairly explicit and equitable load shedding protocol. It is my understanding that on July 3, 1996, the day after the big July 2, 1996 outage, a similar problem occurred. Idaho dropped load for the entire City of Boise, which kept the entire system from going down again. This incident and the smart and timely actions taken by Idaho operators should be proof that a load shedding protocol may limit the severity of outages.

And finally, we need to encourage the participation of all appropriate parties in the process to develop solutions. In particular, the state PUC's need to be involved as honest brokers. A few years ago, it would have been unlikely for state regulators to be welcomed into this kind of problem-solving process, but times have changed. The participation of state PUC representatives in the various western RTGs has been beneficial and has opened new avenues of communication among the parties involved. We need to continue to work together in order to understand and solve this complex reliability problem. Indeed, PUC regulators bring a ground-level public interest perspective of concern for overall reliability and economic efficiency that individual market players may not necessarily bring. Without this broad perspective the narrower interests of market players may dominate reliability protocols. The regulators can help develop a balance between system reliability obligations of non-WSCC members without allowing WSCC members to inhibit the transition to competition under the guise of reliability. While this will be challenging, I and other regulators are ready to meet these challenges.

PREPARED STATEMENT OF E. JAMES MACIAS

ISSUES AND RECOMMENDATIONS CONCERNING THE AUGUST 10, 1996 BONNEVILLE/WESTERN U.S. POWER OUTAGE

On August 10, 1996, the Western United States electrical grid experienced its second major disturbance in two months. In PG&E's opinion, the cause of both events was a lack of effective voltage management by exporting utilities. This lack of adequate voltage management caused a series of line and equipment failures to escalate into massive voltage collapse and grid instability in the Northwest. These instabilities, in turn, led to widespread customer load shedding throughout the Western United States as other utilities' security systems operated automatically to stabilize the grid.

Economic trends in the industry are driving usage of the grid to a greater extent than ever before. These forces are pushing many generators to maximize electrical output for sale to distant markets and retailers to reach further out, in search of low cost supplies. Recent enhancements to the regional grid and open access regulation now make this access to long distance supplies easier. These conditions are increasing regional flows to higher levels than have ever been seen before. This trend will continue.

Higher regional flows and higher capacity operations, however, reduce the tolerance for error. The grid system is designed to handle these flows, but it requires diligent operations and disciplined adherence to detailed operating procedures.

My analogy is driving on a winding road. With ideal weather conditions and at a speed well below the maximum limit, the driver feels safe and complacent even if the car's suspension is poor or the tires are bald and over-inflated. If weather conditions worsen and the driver goes at the speed limit, these same equipment conditions left uncorrected can lead to disastrous results. This is what happened to the western grid operations.

On August 10, less than ideal operating conditions existed. Critical generating and switchyard voltage support equipment was either unavailable or experiencing operating problems. System operators failed to recognize early warning signs of voltage instability in their control areas. Further failure of unreliable equipment led to disastrous results.

Why is voltage management so important? Voltage is the back pressure that allows electricity to flow across wires. To safely control the flow of electricity across a wire network, voltage has to be carefully managed at the generating source, at the consumption end, and at various locations along the path in between. The longer the distance between the generation source and the consumption end, the more difficult the challenge to maintain even voltage levels. Voltage support is provided by generating facilities and by reactive voltage support equipment located at substations.

CORRECTIVE ACTIONS

PG&E's strategy to improve long-term grid reliability has three components. First, PG&E has taken immediate steps to better insulate PG&E customers from grid disturbances that originate outside our control area. These steps are immediate but provide only temporary improvement. Second, PG&E is also working with Western Systems Coordinating Council (WSCC) and North American Electric Reliability Council (NERC) to improve training, operation and monitoring of WSCC wide voltage management. And third, PG&E continues to pursue fundamental structural changes in the industry that will improve reliability operations while market forces drive economic improvements within the industry.

Immediate Actions:

1. PG&E and Bonneville Power Administration have reduced the amount of energy that can flow from Oregon into California at any time, by lowering the rating of the Pacific AC Intertie from 4500 MW to 3200 MW and the DC Intertie from 2990 MW to 2000 MW. This provides greater reliability to the grid by allowing Northwest in-area generation to provide voltage support for local loads, Canadian imports and California exports. Reducing electricity exports out of the Northwest provides greater redundancy on the Intertie wires and limits the amount of long distance energy available to California.

2. PG&E has also increased communication with other utilities. This will help provide PG&E with potential warning of transient operations and give us an opportunity to take additional protective actions.

Improving Regional Operations

1. WSCC has committed to review procedures and training for voltage collapse. The WSCC will review voltage management criteria and utility operator understanding of this criteria. Procedures and training will be enhanced.

2. WSCC will determine compliance with all WSCC operating procedures, especially voltage management. This has already begun.

3. The WSCC is working to establish four regional "Security Centers" (one of which will be PG&E) to exchange data, monitor system conditions for potential reliability problems and coordinate system restoration.

Industry Restructuring

1. PG&E's restructuring proposal to Federal Energy Regulatory Commission (FERC) would separate and isolate reliable grid operation from the economic drivers of the competitive supply market. The Independent System Operation (ISO) will be solely responsible for reliable grid operation and will have no economic interest in the market. Organizational separation of the ISO from the Power Exchange and other supply coordinators will ensure this reliability-only focus.

2. ISO regional control would replace numerous utility-specific control points. Today's regional control is a patchwork of dozens of local utilities coordinating with each other. Regional ISOs are being considered to better monitor system conditions .

3. ISO operating criteria should be mandatory with financial settlements. WSCC operating criteria are largely voluntary. There are very few enforcement consequences in the WSCC. The ISO will make procedures mandatory and will permit/require financial settlement where cost causation can be determined.

Technology Tools

1. Dynamic ratings are needed for transfer capabilities: Today's ratings are conservative, but they are developed on the basis of fixed assumptions of operating conditions and flow patterns. The future market will dictate frequent changes in generation patterns. Grid operators will need more dynamic analysis tools to better assess real time reliable operations.

2. Real - time contingency analysis is needed: Today's operators rely on procedures and protective schemes that are based on a limited number of off-line power flow studies. Frequent changes in power flow patterns and heavy system utilization require the development of tools that will evaluate real-time conditions and alert operators to dangerous conditions.

PREPARED STATEMENT OF MARCIE L. EDWARDS

WRITTEN STATEMENT FROM
THE LOS ANGELES DEPARTMENT OF WATER AND POWER
PRESENTED BY
MARCIE L. EDWARDS
DIRECTOR OF BULK POWER

FOR THE HOUSE
SUBCOMMITTEE ON WATER AND POWER RESOURCES
OVERSIGHT FIELD HEARING ON
"ISSUES AND RECOMMENDATIONS CONCERNING THE AUGUST 10, 1996
BONNEVILLE/WESTERN U.S. POWER OUTAGE"

THE HONORABLE JOHN T. DOOLITTLE, CHAIRMAN
NOVEMBER 7, 1996

Chairman Doolittle and Members of the Water and Power Resources Subcommittee: thank you for this opportunity to share the perspective of the Los Angeles Department of Water and Power on the Western Interconnection disturbance of August 10, 1996. Like most other utilities in the Southwest, the Department experienced significant impacts of a disturbance originating a thousand miles away. Also like other utilities, the Department is committed to learning whatever we can from this event to maintain and improve the reliability of electric power supply in the Western United States.

EFFECTS IN THE DEPARTMENT'S SYSTEM

The disturbance essentially began at 3:42 PM when the 500,000 volt transmission line between Keeler and Alston sagged into a tree, experienced an electrical flashover, and relayed. The power flowing on this line transferred to other weaker lines in the area, overloading them and causing the voltage in the area to decline. At 3:47 PM, the 230,000 volt Ross-Lexington line sagged into a tree and relayed. At the same time, units at McNary Power House began to trip off. The system became unstable, with growing voltage and power oscillations, and after approximately 75 seconds, oscillations grew to where the voltage on the California-Oregon Intertie lines reached the trip setting of relays protecting those circuits. The 4,300 MW which had been flowing into California from the Northwest instantly over those circuits sought a different path to California, through Idaho, Utah, and Arizona. This surge tripped numerous transmission lines in Arizona, Utah and Southern California, creating three electrical islands. A fourth island was created minutes later due to control actions in the Alberta system.

The power swing resulting from the tripping of the three California-Oregon Intertie lines created severe undervoltage conditions in the Southern California area. Most of the Department's load and transmission facilities survived this undervoltage, with two notable exceptions:

- The cooling systems on two solid-state converters on The Pacific High Voltage Direct Current (HVDC) Intertie tripped off due to the low voltage, causing the converters themselves to trip off as well. Additional mercury-arc valve groups may have also tripped off due to the low voltage. As a result, the Pacific HVDC Intertie, which was carrying nearly 2850 MW from the Pacific Northwest to Southern California, was partially disabled. In the minutes after the disturbance was triggered, the Pacific HVDC Intertie, in its weakened conditioned, became a threat to the security of the Southern California system and was intentionally de-energized at the Department's request.

- Pumps at the Hyperion Waste Treatment facility tripped off due to the low voltage, causing partially treated sewage to be dumped into the Santa Monica Bay, forcing the closure of local beaches for a few days after the disturbance.

Eleven generators serving Department load, including units in Utah, Arizona and Southern California, tripped off during the disturbance, mostly due to problems stemming from the power/undervoltage swing. Cut off from the power it had been importing from the Pacific Northwest, the entire southwest island, encompassing Arizona, New Mexico, parts of Baja California, and Southern California, experienced severe underfrequency (58.5 Hz). To stabilize the system and prevent additional loss of load, approximately forty percent of the customers in this region were intentionally and automatically disconnected from the system.

Department load dispatchers used energy from Castaic, a large hydro generating facility north of Los Angeles, to help stabilize the island. Approximately seventy minutes after the disturbance, the frequency had returned to near normal and utilities began to restore customer load. All of the Department's customers were restored to service by 5:30 PM that evening.

ISSUES

The Department actively participated in the Western Systems Coordinating Council's investigation into the disturbance. Additionally, the Department conducted its own in-house investigation into the performance of its system. These investigations brought forth a number of technical and social issues which contributed to the disturbance.

1. INTERCONNECTION-WIDE RESPONSIBILITY FOR RELIABILITY

Competition in the electric power industry promises to do for this industry what telephones, airplanes and even the Internet have done for society at large - effectively shrink the commercial distance between remote parts of the world. In the years ahead, consumers may be purchasing their energy from sources hundreds or thousands of miles away. As the commercial distance between suppliers and consumers on the Interconnected power system shrinks, it will be imperative for all entities deriving economic benefit from the interconnected system to share in the responsibilities for maintaining system reliability. Such steps may include coordinating automatic protective load shedding and restoration, and generator underfrequency or undervoltage protection on an interconnection-wide basis, not just on a local or regional scale. The local or regional practices which have served us well in the past may not be enough to ensure reliability in the competitive future.

2. SHARING TECHNICAL INFORMATION

One of the concerns brought up in the investigation of the August 10 disturbance was whether the Bonneville Power Administration had appropriately made notification of 1) equipment previously out of service for maintenance; 2) three 500,000 volt transmission line outages which occurred in the hours before the disturbance was triggered at 3:42 PM Pacific Advanced Standard Time. While system simulation studies will be necessary to determine the impacts these outages had on the initiation and severity of the disturbance, the fact that some utilities were not aware of these outages raises questions about the flow of information necessary to preserve reliability. The possibility of problems in one part of the interconnected system impacting other remote parts of the interconnected system, coupled with the additional stress competition may place on operating the existing system, increases the need for sharing technical information in a timely fashion.

3. STUDYING AND MONITORING THE SYSTEM

One of the most important factors in the August 10 disturbance was the failure to identify the severe potential impact of a single 500 kV transmission outage (the Keeler-Alston 500-kV line) and implement operating guidelines to mitigate the impacts of that outage. Similarly, the failure to study, assess the impacts of, and develop mitigating guidelines for the loss of two 345-kV transmission lines out of Jim Bridger contributed directly to the July 2, 1996 Western Interconnection disturbance. Unusually favorable water conditions from a wet winter contributed to unusually high levels of Pacific Northwest hydro generation, which in turn created unusual energy flow patterns in the Pacific Northwest - flow patterns which were considered unlikely. As a result, the system may have been operated in a state which had not been studied.

The onset of competition may also create unusual energy patterns which may not have been previously seen or anticipated. Maintaining the reliability of the power system under changing conditions will require intensifying efforts to accurately model and study the system under a wide variety of conditions. These efforts should include the following:

> **Voltage collapse.** A decade ago, simulation studies primarily focused on transient stability, and the ability of the system to survive the first ten or twenty seconds following the loss of an element. More recently, studies have focused also on voltage collapse, a phenomena which can occur in any time frame from a few seconds to several minutes. Studying and protecting against voltage collapse

must become a bigger concern, especially in light of the two Western Connection disturbances of 1996.

Proper modeling of reactive power supplies. The increasing concern over voltage issues has brought forward the need to properly model the reactive power capabilities of generating units. The studies that were done to establish what were believed to be safe operating limits following the July 2 disturbance may have been overly optimistic in modeling the reactive capabilities of generating units, and did not model the uncontrolled loss of McNary units at high levels of reactive output though three McNary units did trip off during the July 2 disturbance.

The North American Electric Reliability Council (NERC) has recommended establishing security centers - regional organizations which will oversee the reliable operations of sections of the interconnected system. Similarly, California has mandated that an Independent System Operator be established to reliably operate the bulk power transmission system. The demand for better, more comprehensive system studies, including, as it becomes more viable, real-time analysis of system security, will probably fall increasingly to these regional security centers.

4. SOCIETAL AND ENVIRONMENTAL IMPACTS ON POWER SYSTEM OPERATION

On August 10, The Dalles, a large hydro generation station in the Pacific Northwest, was operating at reduced capability as part of a program to preserve salmon smolts in the area. This operation reduced the amount of real and reactive power and inertial support available to the Pacific Northwest transmission system, which was operating under stressed conditions at the time.

Such environmentally constrained operations are becoming more commonplace, and are increasing impacting power system operations. For example, even though it contributes a very small portion of the total emissions affecting Southern California air quality, the Department altered the operation of its in-basin units, which provide real and reactive power support to the transmission system serving the City of Los Angeles, to comply with Rule 1135 imposed by the South Coast Air Quality Management District. It is a utility's obligation to comply with the societal and environmental constraints imposed to protect the common good. It is also true that in this energy-dependent society, reliable, economic electric service is also a significant part of the common good, worthy of equal consideration in the public debate.

In summary, Mr. Chairman, the Department believes the major lessons to be learned from this disturbance are:

- the need for old assumptions to be put aside and for all parties deriving benefit from the interconnected system to work together to ensure the continued high degree of system reliability which we have previously enjoyed;
- the need to increase the sharing of technical information even as there is a competition-directed move away from sharing commercial information;
- the need to carefully and completely study a power system which is being operated as never before;
- the need to consider the impacts of constraints imposed on the industry by external concerns.

Thank you again for the opportunity to speak to these issues.

SUPPLEMENTAL SHEET

STATEMENT PRESENTED BY

Ms. Marcie L. Edwards
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SOUTHERN CALIFORNIA
EDISON

Vikram S. Budhraja

November 19, 1996

The Honorable John T. Doolittle
Chairman, Subcommittee on Water and Power Resources
U. S. House of Representatives
1324 Longworth House Office Building
Washington, D.C. 20515

Dear Mr. Doolittle:

I appreciated the opportunity to appear before your committee on November 7, 1996. As you requested, the information on our tree management practices is provided below:

- Edison has an inventory of approximately one million trees, of which 42,600 trees are in our high voltage transmission line rights-of-way.

- We have a 12-month inspection cycle, which includes pre- and post-tree trimming inspection to assure adequate line clearances.

- Our practice is to have a clearance of 40-feet plus 1-year's tree growth for 500 kV lines; and, 25-feet plus 1-year's tree growth for 220 kV lines.

- The use of herbicides is currently limited to weed abatement in substations and transmission rights-of-ways. However, herbicides are not used on U.S. Forest Service lands since use of herbicides have been restricted since 1984.

- Herbicides are not and have not been utilized in our vegetation management program, we rely on traditional tree trimming practices.

- Edison also utilizes a tree removal and replacement program to remove high growth and high maintenance trees that might affect our high voltage transmission lines. Going back at least 5-years, Edison has not had any tree caused outages on the 220 kV or 500 kV transmission lines.

I hope this information is helpful in your inquiry on reliability. Please let me know if we can provide additional information.

Sincerely,

V. Kumar Budhraja

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