BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of PACIFICORP (U 901 E), an Oregon Company, for a Permit to Construct the Lassen Substation Project Pursuant to General Order 131-D.	Application _________

APPLICATION OF PACIFICORP (U 901 E) FOR A PERMIT TO CONSTRUCT THE LASSEN SUBSTATION PROJECT

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Date: November 2, 2015

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Under Rule 2.1 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure and Section IX.B. of General Order (GO) 131-D, PacifiCorp d/b/a Pacific Power (PacifiCorp) respectfully requests the Commission issue a Permit to Construct (PTC) authorizing PacifiCorp to build the proposed Lassen Substation as a replacement to the existing Mt. Shasta Substation and, upon completion of the Lassen Substation, to remove the Mt. Shasta Substation. In connection with the construction of the new substation, PacifiCorp will upgrade associated transmission and distribution lines and install approximately 1,200 feet of underground cable to increase capacity of an existing underground distribution line (collectively referred to as the Lassen Substation Project or Proposed Project).

I. SUMMARY OF REQUEST

With this Application, PacifiCorp respectfully requests the Commission issue and certify an appropriate environmental document and issue an *ex parte* decision granting PacifiCorp a PTC authorizing it to construct the Proposed Project as set forth in this Application, the Proponent's Environmental Assessment (PEA) (attached as Exhibit A), and the accompanying documents, within the proposed timelines set forth in Section XIII of this Application.

II. BACKGROUND

PacifiCorp provides reliable electric service to approximately 45,000 customers in various communities located in northern California, including customers in the area of Mt. Shasta in Siskiyou County. The Mt. Shasta Substation currently delivers power to approximately 4,859 of those customers, the vast majority of which (4,156) are served by a 12.5 megavolt ampere (MVA) transformer.[1] The Mt. Shasta Substation is a severely deteriorated wood structure. Rot and damage caused by birds have brought the structure to near the end of its useful life. This situation has prompted concerns about the Mt. Shasta Substation being able to safely and reliably meet current and future local and contractual system demand.[2]

Accordingly, PacifiCorp proposes to remove the Mt. Shasta Substation and replace it with a new substation -- the Lassen Substation -- that will contain a 69 kV/12.5 kV rated transformer. PacifiCorp will also upgrade associated transmission and distribution lines and install approximately 1,200 feet of underground cable to increase the capacity of an existing underground distribution line. The new substation and upgraded poles will be designed and built to allow for operating within a 115 kV transmission system -- which is the proposed, and in many locations the current, voltage for PacifiCorp's electrical system in the region. For the immediate future, the Lassen Substation and associated transmission line will be operated at 69 kV.

Due to surrounding physical and land use constraints, there is insufficient space to rebuild and expand the existing Mt. Shasta Substation. Accordingly, the Lassen Substation will be located on a parcel of land 275 feet east of the Mt. Shasta Substation site, on property owned by

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1 The remaining 703 customers are served by a 3.75 MVA transformer.

2 An industrial customer has requested connection of new load requiring significantly more transformer capacity than is available at Mt. Shasta Substation.

PacifiCorp. Once the Lassen Substation has been constructed and is operational, PacifiCorp will remove the Mt. Shasta Substation.

After all necessary approvals and permits are obtained, construction is expected to take approximately six months to complete. PacifiCorp seeks to have the Project in operation by December, 2017.

III. DESCRIPTION OF THE PROJECT

As noted above, the Proposed Project consists of the following four elements. Each of these elements are described in brief below and in full in Section 3 of the PEA.

A. Lassen Substation

The proposed Lassen Substation will be an unmanned, automated low-profile electric substation. The substation will have an eight foot high chain-link fence with visual slat screening, and barbed-wire extensions for security, around the footprint of the substation. The Lassen Substation will be a standard low profile substation approximately 280 feet by 212 feet (1.4 acres) to accommodate the necessary equipment. The Lassen Substation site will be surfaced with gravel to reduce the migration of oil spills and additional engineered methods (*e.g.*, concrete berms, petro barriers) will prevent any spills from leaving the new substation site. As part of the construction for the new substation, an existing access road (currently a residential driveway) to the new substation property will require widening and upgrading to allow for safe construction access as well as access for maintenance during operation. The proposed Lassen Substation site consists of two parcels owned by PacifiCorp, comprising approximately 4.5 acres. Construction of the Lassen Substation will be performed entirely within the confines of this property.

B. Transmission Upgrade

PacifiCorp will replace thirty-six (36) wood poles, spanning approximately 1.5 miles, which support the existing 69 kV transmission line that transports bulk electrical power into and out of the existing Mt. Shasta Substation (Line 2). The replacement poles for Line 2 will be framed for 115 kV transmission and a distribution under-build. These poles will be placed immediately adjacent to the existing poles within PacifiCorp's existing right-of-way (ROW), and the old poles will be cut off at ground level. Additionally, three new transmission poles will be constructed to connect Line 2 to the new Lassen Substation.

C. Distribution Upgrade

The Proposed Project also includes upgrades to the existing distribution system in the area of the proposed Lassen Substation to meet current capacity requirements and future load growth. The distribution lines in the area will be upgraded from 4.16 kV lines to 12.47 kV lines. The distribution lines will be partially re-conductored, and the 12.47 kV distribution lines will be connected in a new configuration to receive supply from three breakers at the proposed Lassen Substation. As part of the distribution line upgrade, approximately 1,200 feet of underground cable will be installed to connect the distribution circuits to the Lassen Substation.

D. Removal of Mt. Shasta Substation

Once the proposed Lassen Substation has been constructed and is operational, the above-ground equipment within the existing Mt. Shasta Substation will be removed. Before removal, the soil, conduit, equipment, and steel structures will be tested for environmental hazards (e.g., oil, lead based paint, and asbestos). All hazardous materials will be abated in accordance with applicable federal, State, and local regulations before, or as part of, the removal process.

Removal will include disconnecting and removing all of the equipment including the transformer, breakers, regulators, disconnect switches, fuses, the station light and power transformer, and control cabinets. Oil-filled equipment, such as transformers, will be transported to PacifiCorp's Service Center in Medford, Oregon for storage. Other equipment and waste materials will be disposed of according to State and federal regulations. The existing Mt. Shasta Substation concrete foundation and gravel will remain after removal of the substation. All below-grade facilities will remain in place.

IV. THE APPLICANT

PacifiCorp is a public utility organized and existing under the laws of the State of Oregon. PacifiCorp's principal place of business is: 825 NE Multnomah Street, Suite 2000, Portland, Oregon, 97232.

Communications regarding this Application should be addressed to:

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SQUERI & DAY, LLP
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San Francisco, California 94111
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Please address all formal correspondence and requests regarding this application to:

By E-mail (preferred): datarequest@pacificorp.com

By Facsimile: (503) 813-6060

By Regular Mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

A certified copy of PacifiCorp's Articles of Incorporation, as amended, and presently in effect, was filed with the Commission in A. 97-05-011, which resulted in Commission issuance of D. 97-12-093, and is incorporated herein by reference pursuant to Rule 2.2 of the Commission's Rules of Practice and Procedure.

In compliance with Rule 2.3 of the Commission's Rules, a copy of PacifiCorp's recent financial statements, contained in the Quarterly Report on Form 10-Q, filed on August 7, 2015 for the period ending June 30, 2015 is included herein as Exhibit D.

V. PROPONENT'S ENVIRONMENTAL ASSESSMENT

Under Rule 2.4 of the Commission's Rules of Practice and Procedure, the PEA is included as Exhibit A to this Application.

VI. DETAILED DESCRIPTION OF PROPOSED PROJECT

A detailed description of the proposed Lassen Substation Project is included in Exhibit A, Section 3.

VII. PROJECT SCHEDULE

A proposed schedule for authorization, construction, and commencement of operation of the facilities is attached as Exhibit B.

VIII. PROJECT MAP

Detailed maps of the substation location showing populated areas, parks, recreational areas, scenic areas and existing electrical transmission or power lines within 300 feet of the proposed route or substation are provided in Exhibit A, Section 3.

IX. PROJECT ALTERNATIVES

General Order No. 131-D requires that an Application for a PTC include the "[r]easons for adoption of the power line route or substation location selected, including comparison with alternative routes or locations, including the advantages and disadvantages of each."

In addition to the Project Site, PacifiCorp initially identified six additional locations for the proposed Lassen Substation. However, with the exception of one alternative site discussed below, the other locations were eliminated from further analysis because they are infeasible due to either the restrictions of their location or the fact that they would result in greater environmental impacts than the proposed Project Site.

The Alternative Site retained by PacifiCorp for further evaluation would require the expansion of the existing Mt. Shasta Substation site to either the northeast, which would require the purchase of one acre of wetland, or to the southeast which would require the purchase of one acre of unused, inactive pasture land that is vegetated with non-native grasses. Expansion to the southeast was ultimately determined to be infeasible as the dimensions of the parcel would have prohibited the construction of the proposed larger substation. Ultimately expansion of the Mt. Shasta Substation site to the northeast was also not pursued given the fact that it would require vegetation clearing or filling of approximately one acre of riparian scrub and dry montane meadow wetlands. Even with the implementation of mitigation measures, there would be an area of wetlands permanently impacted through construction of this alternative. The impacts to the wetlands surrounding the existing substation would be significant.

No other alternatives were considered other than the No Project Alternative. The No Project Alternative may result in a reduction of environmental impacts in the short-term, but this Alternative would not meet any of the objectives of the Proposed Project. PacifiCorp's electrical system in the Mt. Shasta area would continue under its deficient condition, resulting in increased potential for system unreliability. Therefore, the No Project Alternative would not adequately meet the objectives of the Proposed Project and was determined to be infeasible.

X. CONSULTATION WITH GOVERNMENT AGENCIES

PacifiCorp has consulted with the following governmental agencies with respect to the purpose and location of the Proposed Project: California Department of Fish & Wildlife; California Department of Transportation; California Environmental Protection Agency; California Native American Heritage Commission; California State Parks; U.S. Fish & Wildlife Service; County of Siskiyou, Departments of Engineering, Planning, Emergency Services, and Roads; Siskiyou County Air Pollution Control District; and the City of Mount Shasta Planning Department. PacifiCorp submitted a letter to each of these agencies asking for their respective positions on the Lassen Substation Project.

As of the date of submittal of this Application, PacifiCorp has not received any responses from the contacted agencies. PacifiCorp, however, has no reason to believe that these agencies will have any significant concerns with the Project.

XI. MEASURES TAKEN TO REDUCE EMF EXPOSURE

Section X.A. of GO 131-D requires that a PTC application describe the measures taken or proposed by the utility to reduce potential exposure to electric and magnetic fields (EMF) generated by the proposed facilities.

In accordance with the Commission's EMF Decision, D. 93-11-013, as affirmed by D. 06-01-042, PacifiCorp will incorporate "no-cost" and "low-cost" magnetic field reduction steps in the design of the substation facility. PacifiCorp's EMF design guidelines include the following measures as options for reducing the magnetic field strength levels from electric power lines: (1) increase the height of overhead lines to reduce EMF strength at ground level; (2) reduce conductor spacing to increase cancellation of the magnetic field and decrease the resultant field strength; (3) minimize current through energy efficiency measures; and (4) optimize phase configuration by "cross-phasing individual circuits to cancel magnetic fields." Use of any of these measures by PacifiCorp is dependent on the configuration of the particular project.

The EMF Decision and PacifiCorp's Guidelines require PacifiCorp to prepare an EMF Field Management Plan (FMP) that specifically delineates the no-cost and low-cost EMF measures that will be implemented as part of the final engineering design for the Project. PacifiCorp's Preliminary FMP is attached as Exhibit C. As stated therein, with respect to the Proposed Project, the calculated electric fields are highest outside of the substation at the first structure where both transmission circuits are located on the pole (pole 13A/48) before being routed to the north and south. At this pole, when the transmission circuit is operated at 69 kV, the maximum calculated electric fields are 0.7 kV/m. When the transmission circuit is operated at 115 kV, the maximum calculated electric fields increase to 2.25 kV/m. The calculated electric field values are unperturbed values and do not include the effects of electric field reduction due to the presence of shielding objects, such as the substation fence, trees, bushes, and other objects. The presence of these types of objects will shield the electric field within their immediate vicinity.

A no-cost and low-cost mitigation measure which PacifiCorp will implement to reduce these electric fields is to extend the proposed substation's fence line on the west side of the substation parallel along the span to Pole 13A/48 which would restrict public access from the area where the 115 kV circuit would enter the substation. If this action were taken, then the calculated electric field for publicly accessible areas would be reduced from 2.25 kV/m to below 0.7 kV/m (a reduction of approximately 321%). With respect to magnetic fields, the primary source in the area near the proposed substation is due to the presence of the 12.47 kV distribution under-build. To reduce the magnetic field, the height of the poles supporting the existing 69 kV and 12.47 kV circuits would be increased.

XII. PUBLIC NOTICE AND REQUEST FOR EXTENSION OF NEWSPAPER PUBLICATION NOTICE REQUIREMENT

A. Notice to Agencies

Under Section XI of GO 131-D, subsection 1.a, PacifiCorp will provide notice of the Application within ten days of filing to: the Planning Commission and Board of Supervisors of Siskiyou County; California Energy Commission; the State Department of Transportation; the Secretary of California Natural Resources Agency; the Department of Fish and Wildlife; the Department of Health Services; the State Water Resources Control Board; the Air Resources Board; the applicable Air Pollution Control District; the applicable California Regional Water Quality Control Board; and the applicable State Department of Transportation's District Office. Additionally, notice will also be given to the U.S. Fish and Wildlife Service, the U.S. Army Corps of Engineers, and the Office of Historic Preservation.

B. Notice to Landowners

Under Section XI of GO 131-D, subsection 1.b, PacifiCorp will provide notice of the Application within ten days of filing to all owners of property within 300 feet of the Lassen Substation site and impacted transmission and distribution rights-of-way.

C. Publication in Local Newspaper

Section XI of GO 131-D, subsection A.1.c, requires notice of the Application to be published not less than once a week for two successive weeks in a newspaper of general circulation within ten days of filing. Given the required content of such notice, in particular the Commission-assigned application number, and the limited publishing dates for the newspaper of general circulation in the Proposed Project area, PacifiCorp seeks either: (a) expeditious assignment of an application number, or (b) an extension of time for completion of this noticing requirement.

Section XI subsection C of General Order 131-D details the required content of all notices given by the applicant in compliance with the General Order. Included within these notice requirements is "the Application number assigned by the CPUC." Such application numbers are received after the application has been processed and accepted for filing by the Commission, which could occur several days after the filing of the application.

The newspaper of general circulation in the Project area in which PacifiCorp will place the notice -- the Mt. Shasta Herald, Dunsmuir News, and Weed Press -- publishes weekly on Wednesdays. Advertisements and notices must be submitted to the paper on Monday for publication the following Wednesday. [3]

Accordingly, unless PacifiCorp receives the assigned application number for the Application within four days of filing, it will not be able to meet the deadline for submitting a notice with all the required content to the newspaper for publication within ten days of filing the Application.[4] Accordingly, PacifiCorp requests either: (a) expeditious assignment of an application number so that it can timely complete the required newspaper notification, or (b) a seven day extension to complete this requirement.

A declaration of mailing and posting will be filed with the Commission after completion.

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[3] *See* Exhibit E, Declaration of Natalie Cooper regarding the newspaper publication limitations in the Project area.

[4] For example, if PacifiCorp filed on a Monday, unless it received the required application number by Wednesday it could not submit the notice for timely publication the following Wednesday and the notice would not be published within the 10 day period required by the General Order.

XIII. SCOPING INFORMATION

<u>Proposed Category</u>: Applicant proposes that the Commission classify this proceeding as ratesetting. Although this Application does not affect rates, the definitions of "adjudicatory" or "quasi-legislative" as set forth in Rule 1.3(a) and (d) clearly do not apply to this Application. Rule 7.1(c)(2) specifies that when a proceeding does not clearly fit any of the categories, it should be conducted under the ratesetting procedures.

<u>Need for hearing</u>: PacifiCorp does not believe that approval of this Application will require hearings. PacifiCorp has provided ample information, analysis, and documentation that provide the Commission with a sufficient record upon which to grant the relief requested on an *ex parte* basis. PacifiCorp respectfully requests that the relief requested in this Application be provided on an *ex parte* basis as provided for in G.O. 131-D, Section IX.B.6.

<u>Issues to be considered</u>: The sole issue in this proceeding is whether construction and operation of the proposed Project will be consistent with applicable environmental and land use considerations.

<u>Proposed Schedule</u>: Applicant proposes the following schedule:

November 2, 2015 – Application submitted

November 5, 2015 – Application noticed in Commission's calendar

November 23, 2015 – File a Declaration of Mailing and Posting

December 2, 2015 – Application Completeness Determined

December 4, 2015 – Last day for protests; application deemed complete

July 2016 – Draft CEQA Document (Mitigated Negative Declaration) Issued for Public Comment

August 2016 – Close of Public Comment Period

September 2016 – Draft Decision Issued

October 2016 – *Ex Parte* Decision Issued. Final CEQA Document Certified

XIV. REMITTANCE OF FEES FOR RECOVERY OF COSTS IN PREPARING ENVIRONMENTAL DOCUMENT

In connection with this its review of this Application, the Commission, as lead agency under CEQA, will be preparing the appropriate environmental document (*i.e*., environmental impact report or mitigated negative declaration). Accordingly, pursuant to Rule 2.5 of the Commission's Rules of Practice and Procedure, PacifiCorp will be remitting to the Commission a total deposit of $36,400 towards the cost of such preparation. In accordance with Rule 2.5, this deposit is based upon estimated capital cost of the project, with PacifiCorp remitting one-third of the deposit concurrent with the filing of this Application.

XV. EXHIBITS

The following exhibits are attached and incorporated by reference to this Application:

Exhibit A – Proponent's Environmental Assessment

Exhibit B – Proposed Project Schedule

Exhibit C –EMF Field Management Plan

Exhibit D – PacifiCorp's Financial Statements

Exhibit E -- Declaration Regarding Newspaper Publication Limitations in Project Area

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XVI. CONCLUSION

Wherefore, PacifiCorp requests that the Commission: (1) accept its application as complete; (2) prepare a Mitigated Negative Declaration regarding the potential environmental impacts of the Proposed Project; and (3) issue an expedited *ex parte* decision granting PacifiCorp a Permit to Construct the Lassen Substation Project, as described in this application and the supporting documents.

Moreover, as referenced above, PacifiCorp seeks either: (a) expeditious assignment of an application number, or (b) an extension of time for completion of the newspaper noticing requirement set forth in General Order.

Respectfully submitted this November 2, 2015at San Francisco, California.

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By *\/s\/ Jeanne B. Armstrong*
Jeanne B. Armstrong

Attorneys for PacifiCorp

VERIFICATION

I am an attorney for the applicant, herein; said applicant is absent from the County of San Francisco, California, where I have my office, and I make this verification for said applicant for that reason; the statements in the foregoing document are true of my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed this 2nd day of November 2015, at San Francisco, California.

/s/ Jeanne B. Armstrong
Jeanne B. Armstrong

3219/016/X176655.v1

EXHIBIT A

PROPONENT'S ENVIRONMENTAL ASSESSMENT FOR THE APPLICATION OF PACIFICORP (U 901 E) FOR A PERMIT TO CONSTRUCT THE LASSEN SUBSTATION PROJECT

(DUE TO THE SIZE OF THE FILING IT IS BEING SUBMITTED BY WAY OF ARCHIVAL GRADE DVD)

EXHIBIT B

PROPOSED PROJECT SCHEDULE

PROPOSED PROJECT SCHEDULE

Final engineering completed -- August 2016

Permit to Construct decision adopted and effective -- October 2016

Acquisition of required permits October 2016 – December 2016

Construction begins -- December 2016

Transmission line construction -- December 2016 – July 2017

Distribution line upgrade -- December 2016 – August 2017

Substation construction -- December 2016 – December 2017

Removal of Mt. Shasta Substation/Cleanup -- September 2017 - November 2017

Project operational -- December 2017

EXHIBIT C

EMF FIELD MANAGEMENT PLAN

October 16, 2015

PACIFICORP

Lassen Substation

Electric and Magnetic Field Assessment

Revision B

PROJECT NUMBER:
136412

PROJECT CONTACT:
Kurt Bell, P.E
EMAIL:
kbell@powereng.com
PHONE:
208-288-6343

POWER ENGINEERS

ELECTRIC AND MAGNETIC FIELD ASSESSMENT

PREPARED FOR: *PACIFICORP*

PREPARED BY:

KURT BELL, P.E. – 208-288-6343 – KBELL@POWERENG.COM
KIP PRENTICE – 208-288-6436 – KIP.PRENTICE.POWERENG.COM
SIVASIS PANIGRAHI, P.E. – 503-892-6742 – SPANIGRAHI@POWERENG.COM

REVISION HISTORY						
REV.	ISSUE DATE	ISSUED FOR	PREP BY	CHKD BY	APPD BY	NOTES
A	09/23/15	Prelim	GKB	KPP	SP	Issued for client's review and approval
B	10/16/15	Apprvl	GKB	KPP	SP	Issue for review and approval

"Issued For" Definitions:

- "Prelim" means this document is issued for preliminary review, not for implementation
- "Appvl" means this document is issued for review and approval, not for implementation
- "Impl" means this document is issued for implementation
- "Record" means this document is issued after project completion for project file

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1.0 EXECUTIVE SUMMARY

PacifiCorp is proposing to construct a new substation, the Lassen Substation, near the City of Mt. Shasta, south of Weed, California. The proposed Lassen Substation would serve load in the surrounding area. PacifiCorp will replace the thirty-six (36) wood poles, spanning approximately 1.5 miles, which support the existing 69 kV transmission line that transports bulk electrical power into and out of the existing Mt. Shasta Substation (Line 2) ("pole replacement section'). The replacement poles for Line 2 will be framed for 115 kV transmission as well as an distribution under-build. In addition, there will be changes to local 12.47 kV distribution lines in the area of the City of Mt. Shasta; one circuit will be reconductored north of the Lassen Substation to a light industrial. facility, a new overhead circuit will be installed over Interstate I-5 north of the Lassen Substation (near Hatchery Lane), and a circuit will be removed north of the Lassen Substation.

Computer modeling was performed to calculate power-frequency electric and magnetic field levels resulting from the operation of the proposed substation for comparison with existing field conditions. These models were based upon the 69/115 kV substation design, such as the proposed Lassen Substation, with power line configurations provided by PacifiCorp. The terrain was assumed to be relatively flat across the proposed substation site. Electrical power to the proposed Substation will be supplied from an existing 69 kV circuit which will be uprated to 115 kV in the future. Accordingly, computer modeling was performed for two conditions: 1) the existing configuration of overhead 69 kV transmission circuits from Weed Junction Substation to the north and Mott Switching Station to the south with 12.47 kV distribution circuits underground in the substation and underbuild on the transmission lines; and 2) the 69 kV transmission circuits uprated to 115 kV with the same distribution circuit configurations.

Maximum loading conditions for the 69/115 kV circuits and 12.47 kV circuits were provided by PacifiCorp. Current unbalance of 5% for the 12.47 kV circuits was assumed for this investigation. Electric and magnetic field calculations were performed and contour maps produced for the proposed substation site. In addition, profiles were produced along the substation property line, the substation fence line, and a profile for a typical span of the local distribution lines.

The results of these calculations are summarized in Table 1. The range of values represent the electric and magnetic field values across the substation, at various locations of the property boundary and the across the profiles along the lines. The calculated electric field values are unperturbed values and do not include the effects of electric field reduction due to the presence of shielding objects, such as the substation fence, trees, bushes, and other objects. The presence of these types of objects will shield the electric field within their immediate vicinity.

For the electric fields, in the 69 kV transmission line scenario (in the pole replacement section), the highest calculated electric field (along the line outside of the substation) of about 0.25 kV/m occurs in the span between Poles 13A/48 and 13/48. For the 115 kV transmission line scenario, in the pole replacement section, the highest calculated electric field (along the line outside of the substation) of about 0.4 kV/m occurs in the span between Poles13A/48 and 13/48. At the location of the property boundary line where the two transmission circuits enter the substation, the maximum calculated electric field at the pole outside the substation is 0.7 kV/m for the 69 kV scenario and 2.25 kV/m for the 115 kV scenario.

For the magnetic fields, the calculations show that the dominant sources of such magnetic fields outside of the substation are due to the presence of the unbalanced currents on the 12.47 kV distribution lines. In the pole replacement section, the highest calculated magnetic field of approximately 50 mG occurs for the span 12/48 -13/48 outside of Lassen Substation. At the southeast side of the property boundary line, the maximum magnetic field level is approximately 250 mG which is due to the distribution lines. Outside of and away from the proposed substation property, the calculated magnetic field remains virtually unchanged between the existing and proposed substation configurations. Inside the substation magnetic fields are predicted to be a maximum of approximately 2,200 mG.

TABLE 1: SUMMARY OF ELECTRIC AND MAGNETIC FIELD CALCULATIONS FOR THE PROPOSED LASSEN SUBSTATION POLE REPLACEMENT AREA

Modeling Location	Electric Field		Magnetic Field[1]	
	69 kV (kV/m)	115 kV (kV/m)	69 kV (mG)	115 kV (mG)
Inside Substation	.01 – 3.5	0.02 – 5.75	10 - 2,175	20 – 2,200
Pole to West Outside Substation	0.7	2.25	28	12
Substation Fence	0.1 – 1.9	0.15 – 3.5	10 - 250	10 - 250
Property Line Boundary	.02 – 1.64	0.3 – 1.9	1.25 - 25	1.25 - 25
Pole 13A/48 to Lassen Substation	0.125 – 0.75	0.205 – 1.25	8 - 16	8 – 10
Pole 13A/48 – Pole 13/48	0.025 – 0.25	0.025 – 0.4	25 - 46	24 - 45
Pole 13A/48 – Pole 13B/48	0.02 – 0.135	0.03 - 0.205	22 - 29	23 - 40
Pole Spans 13B/48 – 14/48 – 14A/48	0.0225 – 0.103	0.04 – 0.155	16 - 32	16 - 28
Pole 15/48 – Pole 16/48	0.025 – 0.125	0.07 – 0.21	40 - 130	9 - 18
Pole 12/48 – Pole 13/48	0.025 – 0.115	0.03 – 0.145	24 - 51	24 - 50
Pole 11/48 – Pole 12/48	0.0225 – 0.11	0.03 – 0.145	7 - 50	7 - 49
Pole 19/47 – Pole 20/47	0.02 – 0.095	0.0375 – 0.135	3 - 36	4 - 34
Pole 20/48 – Pole 21/48	0.03 – 0.11	0.05 – 0.165	3 - 19	2 - 19
Additional 12.47 kV Lines[2]	0.005 - 0.022 kV/m		3 – 22 mG	

1. Magnetic fields are calculated based on maximum loads provided by PacifiCorp.
2. The electric and magnetic fields ranges are more a profile distance of 80 feet each side of the center line.

The calculated electric and magnetic levels for the proposed project are below the guidelines (described in Section 9) developed by ICNIRP and IEEE for publicly accessible areas. With respect to the guidelines developed by the ACGIH, calculated electric and magnetic field levels at publicly accessible areas are below the levels cited, with the exception of one small area. This area is directly underneath the 69 kV circuit as it drops down into the proposed substation and has unperturbed calculated electric field levels above 1 kV/m, which is above the ACGIH guideline for workers with cardiac pacemakers. However, these calculated electric field levels are unperturbed values, and the presence of the substation fence, the structural steel pole, and any other types of grounded objects in this area will shield the electric field within their immediate vicinity and may reduce field levels below 1 kV/m (the amount of field reduction would depend upon the quantity, types, size, and other characteristics of these potential shielding objects).

For electric field mitigation, the area with the highest calculated field increase occurs for the 69/115 kV transmission line span into the substation. A no-cost/low-cost mitigation option would be to extend the proposed fence line on the west side of the substation along the span to Pole 13A/48 a distance of approximately 20 feet on both sides of the center line which would restrict public access from this area of higher electric fields. In addition, the presence of the extended substation fence would also provide some electric field shielding within its immediate vicinity and would therefore reduce electric fields within this area.

For magnetic field mitigation, calculated levels from the proposed substation equipment are reduced to background levels at the edge of the proposed substation fence. The main source of magnetic field is the presence of the existing overhead power lines, and in particular, the distribution underbuild. Therefore, no changes to the existing power line configuration or proposed substation design for magnetic field mitigation are recommended.

2.0 INTRODUCTION

PacifiCorp is proposing to construct a new substation, the Lassen Substation, in an unincorporated area of Siskiyou County east of Old Stage Road and immediately southeast of the existing Mt. Shasta Substation. Initially, the proposed Lassen Substation would convert 69 kV electrical power to 12.47 kV for distribution to the surrounding area. The existing 69 kV transmission line traverses the northeastern corner of the subject property. In the future, the 69 kV transmission line will be uprated to 115 kV. Within the proposed substation, electrical power would then be routed through buswork to a single transformer, where the voltage would be converted to 12.47 kV for distribution. Associated buswork would then carry 12.47 kV electrical power to two existing and one new distribution feeder circuits.

As a result of the addition of the Lassen Substation, thirty six transmission line poles would be modified due to the increase loading and addition of distribution circuits; nineteen poles from the location of the existing Mt Shasta Substation towards Weed Junction Substation, and seventeen transmission line poles from the location of the existing Mt. Shasta Substation towards Mott Switching Station.

A power-frequency electric and magnetic field assessment for the project was performed, including computer modeling of the 60 Hertz electric and magnetic fields resulting from the operation of the proposed substation. Calculated electric and magnetic field levels were based on computer modeling of the existing overhead 69 kV circuit (which also has an existing 12.47 kV distribution underbuild), the future uprate of the 69 kV line to 115 kV, and the initial design of the proposed substation. This report presents the electric and magnetic field computer modeling results for this assessment.

3.0 UNITS OF MEASURE

Magnetic flux densities (B) are reported in units of gauss (G), or more typically in units of milliGauss (mG), which are equal to one-thousandth of a gauss (i.e., 1 mG = 0.001 G). Some technical reports also use the unit Tesla (T) or microTesla (μT; 1 μT = 0.000001 T) for magnetic flux densities. The conversion between these units is 1 mG = 0.1 μT and 1 μT = 10 mG.

For electric field quantities, values are reported in kilovolts per meter (kV/m).

4.0 DESCRIPTION OF ELECTRIC AND MAGNETIC FIELDS

Electric and magnetic fields occur throughout nature and are one of the basic forces of nature. Any object with an electric charge on it has a voltage (potential) at its surface and can create an electric field. The change in voltage over distance is known as the electric field. When electrical charges move together (known as "current"), they create additional forces on each other. These additional forces are represented by magnetic fields. All currents create magnetic fields.

For extremely-low-frequency fields, the strength of electric and magnetic fields are related to the voltage and current respectively, and to the distance away from the source. The strength of the electric field depends on the voltage (higher voltages create higher electric fields) and the distance (electric fields grow weaker as distance from the source increases). Similarly, magnetic field strength depends on current (higher currents create higher magnetic fields) and the distance (magnetic fields grow weaker as distance from the source increases). At frequencies much higher than power frequency (60 Hz), such as radio frequencies, the electric and magnetic field can be interrelated.

Electric and magnetic fields can be static (unchanging) in direction (direct current, DC) or changing/alternating in direction (alternating current, AC). Static electric fields can result from taking off a sweater or walking across a carpet. Body voltages as high as 8,000 to 16,000 volts (8 - 16 kV) have been measured on a person as a result of walking across a carpet [1]. The earth has a natural static electric field of about 120 to 150 volts/meter (0.12 - 0.15 kV/m) at ground level due to the 300-400,000 volt potential difference between the ionosphere and the earth [2]. This means that a six-foot tall person would have a static potential of about 275 volts between the top and bottom of their body. Much stronger static electric potentials can exist underneath clouds, where the electric potential to earth can reach 10-100 million volts. Natural static electric fields under clouds and in some dust storms can reach 30 to 10 kV/m [2,3]. Static magnetic fields also occur in nature. The earth has a natural static magnetic field of about 500 mG in the Mount Shasta, California area [4].

The electric power distribution system, wiring in buildings, and electrical appliances create alternating (AC) electric and magnetic fields. In the United States, the power system uses current that alternates 60 times each second (60 Hertz). Almost all-household appliances create an electric field. This is due to the voltage on the appliance. To create an electric field, the appliance need not be operating, but just plugged into the wall socket. Typical reported values measured one foot away from some common household appliances are shown in Table 2 [5].

TABLE 2: TYPICAL ELECTRIC FIELD VALUES AT 12" FROM COMMON APPLIANCES	
Appliance	**Electric Field (kV/m)**
Electric Blanket[1]	0.250
Broiler	0.130
Stereo	0.090
Refrigerator	0.060
Iron	0.060
Hand Mixer	0.050
Toaster	0.040
Hair Dryer	0.040
Coffee Pot	0.030
Clock	0.015

1. Electric fields can reach 1 - 10 kV/m next to the blanket wires.

Overhead electric transmission and distribution lines also create 60 Hz electric fields. The strength of the electric field is primarily a function of line voltage, height of the conductors above ground, the arrangement of the electrical wires, and distance away from the line. Unlike magnetic fields, electric fields can easily be shielded (or weakened) by the presence of conducting objects. For example, a typical house shields about 90 - 95 percent of electric fields from the outside sources [6]. Other objects, such as trees, shrubs, walls, and fences, will also provide electric field shielding. Underground transmission lines do not produce electric fields, since the earth shields the electric field.

Electric field levels within buildings near the substation were not considered as part of this project evaluation. Building structures themselves provide electric field shielding from external sources; therefore, the existing overhead power lines and proposed substation equipment will not significantly influence internal electric field levels within nearby buildings.

The 60 Hz magnetic fields under most overhead transmission and distribution lines are usually smaller than values near many common household appliances. The main reason for this is the height above ground at which electric power lines are supported. Since the field decreases with distance away from the source, the line height above ground effectively reduces the magnetic field to levels that are less than many appliances.

The characteristics of magnetic field attenuation can differ depending on the field source. A magnetic field due to a point source, such as an appliance, decreases rapidly with distance away from the device. The magnetic field also decreases with distance away from linear sources, such as overhead power lines, but not as rapidly as it does with appliances. Overhead transmission line magnetic fields attenuate at a rate that is inversely proportional to the distance squared, whereas magnetic fields from appliances and other point sources attenuate at a rate proportional to the distance cubed. Underground transmission line magnetic fields attenuate more rapidly than those produced by overhead transmission lines, since the current-carrying conductors are typically in closer proximity to each other, thereby increasing field cancellation and the attenuation rate. Since the magnetic field is caused by the flow of an electric current, a device must be operated for it to create a magnetic field. The magnetic field of a large number of typical AC household appliances was measured by the Illinois Institute of Technology Research (IITRI) for the U.S. Navy [7] and by Enertech Consultants [8] for the Electric Power Research Institute (EPRI). Typical values for appliances are presented in Table 3. Another study by Enertech Consultants [9] for EPRI found that mean resultant AC magnetic fields in residential U.S. homes was about 0.9 mG (at 1 meter above ground level). Another study by Enertech for the U.S. Department of Energy [10] found that mean AC magnetic fields in office buildings was about 0.7 to 0.8 mG.

TABLE 3: MAGNETIC FIELDS DUE TO TYPICAL HOUSEHOLD APPLIANCES

	Magnetic Field - mG	
Appliance	**12" Away**	**Maximum**
Electric Range	3 – 30	100 - 1,200
Electric Oven	2 - 5	10 - 50
Garbage Disposal	10 - 20	850 - 1,250
Refrigerator	0.3 - 3	4 - 15
Clothes Washer	2 - 30	10 - 400
Clothes Dryer	1 - 3	3 - 80
Coffee maker	0.8 - 1	15 - 250
Toaster	0.6 - 8	70 - 150

TABLE 3: MAGNETIC FIELDS DUE TO TYPICAL HOUSEHOLD APPLIANCES		
	Magnetic Field - mG	
Appliance	**12" Away**	**Maximum**
Crock Pot	0.3 - 1	15 - 80
Iron	1 - 3	90 - 300
Can Opener	35 - 250	10,000 - 20,000
Mixer	6 - 100	500 - 7,000
Blender, Popper, Processor	6 - 20	250 - 1,050
Vacuum Cleaner	20 - 200	2,000 - 8,000
Portable Heater	1 - 40	100 - 1,100
Fans/Blowers	0.4 - 40	20 - 300
Hair Dryer	1 - 70	60 - 20,000
Electric Shaver	1 - 100	150 - 15,000
Color TV	9 - 20	150 - 500
Fluorescent Light	2 - 40	140 - 2,000
Fluorescent Desk Lamp	6 - 20	400 - 3,500
Circular Saw	10 - 250	2,000 - 10,000
Electric Drill	25 - 35	4,000 - 8,000

Magnetic fields can be present due to a variety of different field sources. Contributions from multiple field sources are not simply cumulative in determining the resulting magnetic field level, since magnetic fields are vectors and phasors, and thus, add vectorially [11]. When the vectors are in opposite directions the fields cancel, and when the vectors are in the same direction they add. The magnetic field at any point in space is the vector sum of the field contributions from all sources (at each instant in time) [11]. Magnetic fields from multiple sources are influenced by the distance relative to each source, the amount of current on each source, and the configuration of the source (i.e., the arrangement of the current-carrying conductors associated with the source). Since the spatial and time components of magnetic fields from various sources are not always known, a good estimation of their additive effect assumes that they will add in quadrature as an rms value.

Unlike electric fields, most ordinary objects cannot easily shield magnetic fields. Many common materials (wood, air, concrete, earth, people, etc.) do not shield magnetic fields. However, ferromagnetic materials such as iron or steel can shield them.

5.0 DESCRIPTION OF LASSEN SUBSTATION PROJECT

The site of the proposed Lassen Substation is located near the City of Mt. Shasta, south of Weed, California. The proposed Lassen Substation would initially convert 69 kV electrical power to 12.47 kV for distribution to the surrounding area. An existing 69 kV transmission line from Weed Junction Substation would be utilized to provide power to the substation. In the future, the voltage on this 69 kV transmission line and the proposed substation will be upgraded to 115 kV to provide additional capacity.

The proposed substation design would tap into an existing 69 kV overhead transmission line circuit from Mt. Shasta Substation. Power would be routed to the 69 kV buswork within the substation, and then carried through the substation to a single power transformer. Once the power is converted to 12.47 kV for distribution, it would be routed through lower voltage buswork to three underground distribution feeder circuits (two of the distribution circuits are existing and one circuit is new).

There are additional changes being made to the local 12.47 kV distribution system:

- The 12.47 kV circuit to the new Crystal Geyer Water Co. facility will be reconductored and a new section of underground will be installed near Interstate I-5.
- The section of the 12.47 kV circuit near Hatchery Lane across Interstate I-5 will be converted to an overhead line.
- The 12.47 kV circuit just north of the proposed Lassen Substation will be removed.

Figure 1 depicts the Lassen Substation project area. Figure 2 represents an aerial photograph of the proposed site overlaid with the initial substation design.

Appendix A presents the substation design, power line configuration, and loading information provided by PacifiCorp. Field calculations were performed for maximum load conditions for the 69 kV and 115 kV circuits. Since the 69 kV circuit (115 kV future circuit) is the end of a radial branch which only serves one substation, all of the 69 kV load would flow into the proposed substation. The resulting load on the three 12.47 kV underground distribution circuits was assumed to divide evenly between the three 12.47 kV circuits. Table 4 summarizes the load values used for these field calculations.

TABLE 4: SUMMARY OF POWER LINE LOADING CONDITIONS

Power Line Description	Maximum Load (Amperes)
69 kV Circuit	264
115 kV Circuit	106
12 .47 kV Circuits	476

6.0 COMPUTER MODELING

Power-frequency electric and magnetic field calculations for the proposed Lassen Substation were performed using the Current Distribution, Electromagnetic interference, Soil, and Grounding analysis (CDEGS) computer software program (Version 13.4.28). CDEGS is a software program which was developed by Safe Engineering Services (SES). The HIFREQ module of the CDEGS software program was used to calculate the electric and magnetic fields from the transmission line, distribution lines, and substation buswork sources along with other passive conductors in the substation (bus structures, steel poles, fence, ground grid conductors, and the buildings). This modeling program contains several unique features, including three-dimensional modeling, multiple loading conditions, multiple calculation grids and profiles, and EMF values in air and soil along well defined paths due to buried or in-air power system conductors. The 69/115 kV and 12.47 kV circuits are energized simultaneously using current injection and voltage sources. The calculation results from the CDEGS software were used to generate the electric and magnetic field contour maps and profile plots used in this report. Calculations were performed at 1 meter (3.28 feet) above ground level (in accordance with IEEE Standard 644-1994 [12]).

The Bonneville Power Administration's BPA Corona and Field Effects Program (Version 3) was used to calculate the electric and magnetic fields for the local 12.47 kV single circuit lines.

PacifiCorp provided all of the substation, transmission line, and distribution feeder design information, including the preliminary substation layout drawings, overhead transmission and distribution line configurations, line routing, loading, and related information. Appendix A presents a summary of the substation and transmission line geometry information provided by PacifiCorp.

Two different case studies were created for this evaluation. One study was developed to analyze the existing 69 kV transmission line with the three 12.47 kV distribution circuits. The second study was developed to analyze the future 115 kV transmission line with the three 12.47 kV distribution circuits. Figures 3 and 4 depict plan and profile views of the model of the Lassen Substation and the transmission line and distribution lines in the immediate area of the substation.

7.0 MODELING ASSUMPTIONS

Computer modeling of the proposed substation and associated power lines required certain assumptions. The basic computer model was created using PacifiCorp aerial photographs of the proposed substation site and information shown in Appendix A. Computer models were based upon the preliminary 69/115 kV substation design for the proposed Lassen Substation. Appendix A presents a summary of the substation and transmission line geometry information provided by PacifiCorp.

The assumptions are as follows:

1. The terrain was assumed to be relatively flat across the proposed substation site where modeling was performed.

2. Calculated electric field values are unperturbed field values, and these values will be influenced by the presence of shielding objects such as trees, bushes, fences, buildings, and other grounded objects.

3. The presence of these objects will shield the electric field within their immediate vicinity.

4. Maximum loading is assumed for all transmission and distribution circuits.

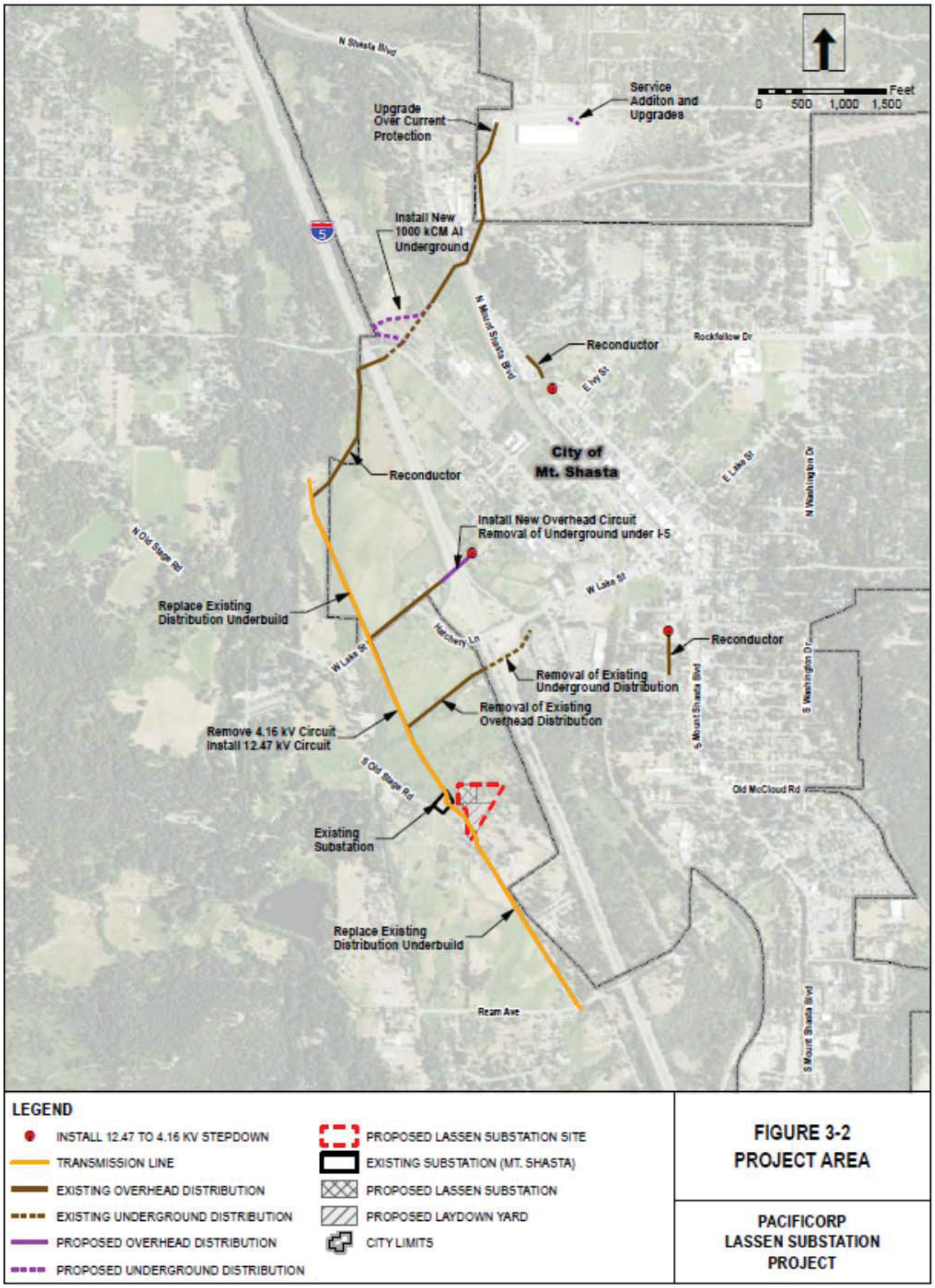

Figure 1: Lassen Substation Project Area

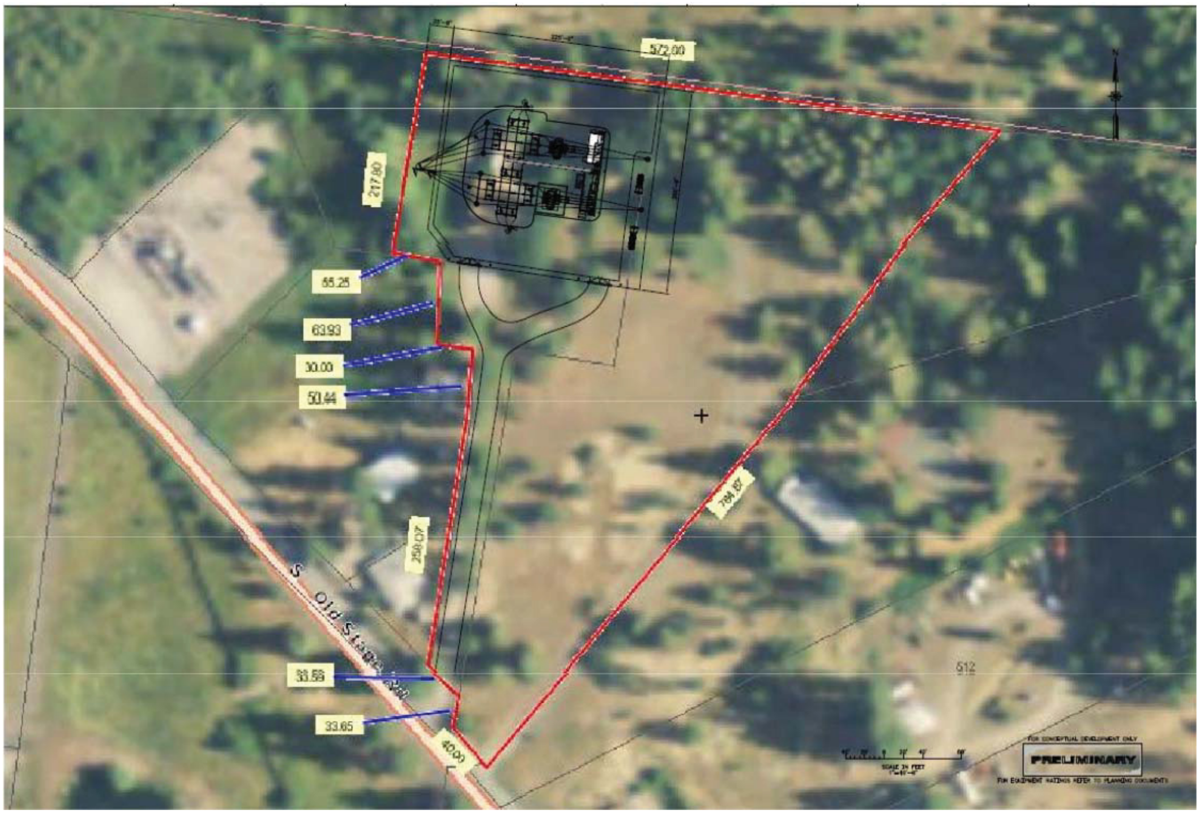

Figure 2: Aerial Photograph of Proposed Lassen Substation Site with Property Boundaries

8.0 RESULTS

8.1 GENERAL EMF COMPUTER MODELING RESULTS

Electric and magnetic field calculations were performed for the entire study area which includes the Lassen Substation property and the transmission/distribution line route based on the 36 structures that are being replaced (Pole 19/47 in the north end of the corridor to Pole 2A/49 in the south end of the corridor).

An electric and magnetic field contour plot are shown in Appendix B.

8.2 ELECTRIC FIELD COMPUTER MODELING RESULTS

The CDEGS and BPA CAFEP software provides calculated electric field values in Volts/meter. The electric field values in kV/meter are one-thousandths of the calculated values. The legends of the contour plots actually show contour levels in kV/m. The calculations are unperturbed electric fields that mean the electric fields do not take into account effects from objects.

Figures 5 - 8 are electric field contour plots for the existing 69 kV system. Figures 9 – 12 are electric field contour plots for the future 115 kV system.

The highest calculated electric fields for the study area exist in the substation. The maximum calculated electric field for the existing 69 kV system is 3.5 kV/m and the maximum calculated electric field for the future 115 kV system is 5.75 kV/m. These electric fields are primarily due to the 115 kV bus work.

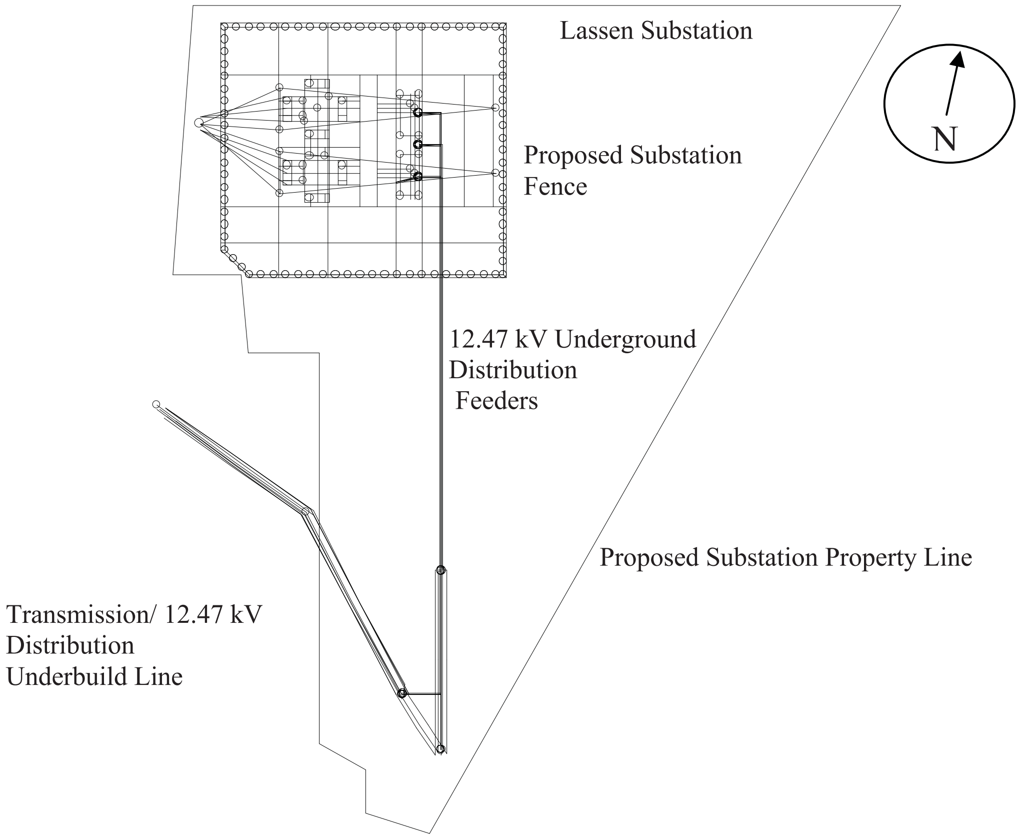

Figure 3: Plan View of the Computer Model for the Proposed Lassen Substation Site with the 69/115 kV Transmission Line and 12.47 kV Distribution Lines

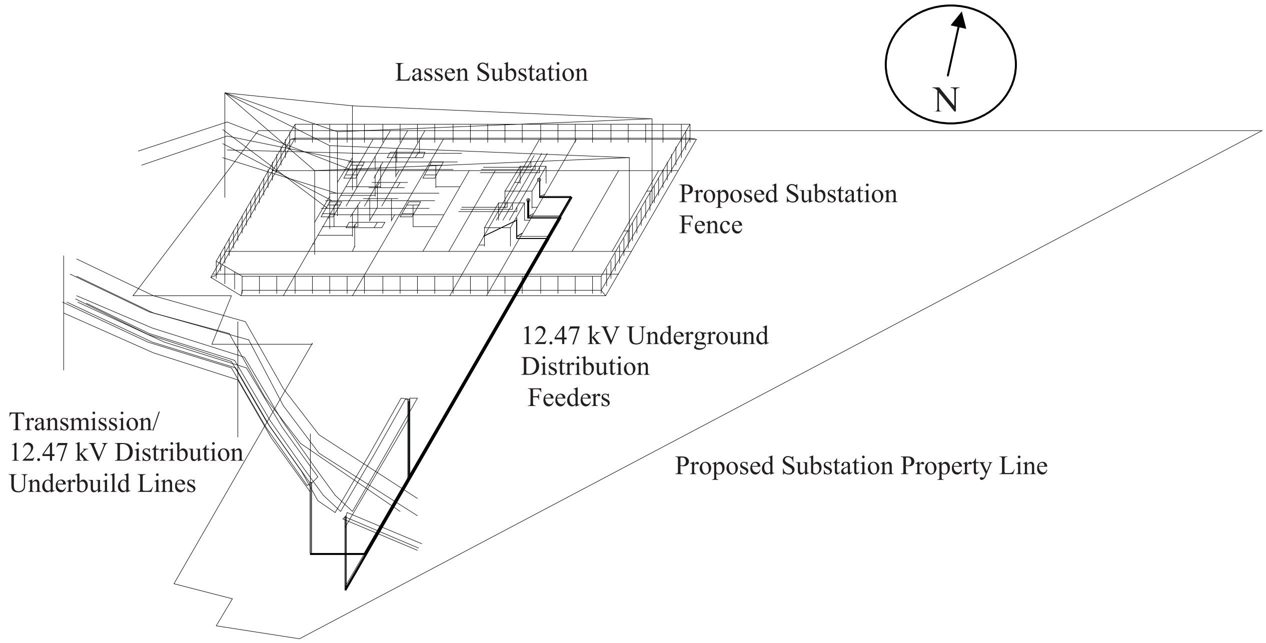

Figure 4: Profile View of the Computer Model for the Proposed Lassen Substation Site with the 69/115 kV Transmission Line and 12.47 kV Distribution Lines

For the existing 69 kV system, the calculated electric fields range from 0.02 kV/m on the east side of the property line boundary to 1.6 kV/m on the west side of the property line boundary (which is due to the transmission lines being routed from this side of the property). For the future 115 kV system, the calculated electric fields range from 0.3 kV/m on the east side of the property line boundary to 1.9 kV/m on the west side of the property line boundary. The calculated electric fields are highest outside of the substation at the first structure where both transmission circuits are located on the pole before being routed to the north and south (the model was based on the circuits having the same phasing which produces the most conservative electric fields). At this pole, the maximum calculated electric fields are 0.7 kV/m and 2.25 kV/m for the existing 69 kV system and future 115 kV system respectively.

The transmission line span from the substation to Pole 13/48 has both circuits. At midspan (lowest point of the phase conductor to ground) the maximum electric field is 0.75 kV/m and 2.25 kV/m for the 69 kV system and 115 kV system respectively.

The highest electric fields for the single circuit transmission line spans in the area of the pole replacements are 0.25 kV/m and 0.4 kV/m for the 69 kV system and 115 kV system respectively.

The range of electric fields for the local 12.47 kV distribution lines is from 0.005 to 0.022 kV/m.

The presence of electric field shielding objects, such as the substation fence, trees, bushes, and other objects do not influence these unperturbed electric field calculations. The presence of these types of objects will shield the electric field within their immediate vicinity. Outside of and away from the proposed substation property, the calculated electric field remains virtually unchanged.

8.3 MAGNETIC FIELD COMPUTER MODELING RESULTS

The CDEGS and BPA CAFEP software provides calculated magnetic field values in milliGauss (mG).

Figures 13 - 19 are magnetic field contour plots for the existing 69 kV system. Figures 20 – 26 are magnetic field contour plots for the future 115 kV system. Figure 27 is the magnetic field strength profile plot for the single circuit 12.47 kV distribution line.

For magnetic fields, the main source of fields is the presence of the existing overhead power lines, and in particular, the distribution underbuild.

The highest calculated magnetic fields for the study area exist in the substation. The maximum calculated magnetic field for the existing 69 kV system is 2,175 mG and the maximum calculated magnetic field for the future 115 kV system is 2,200 mG. These magnetic fields are primarily due to the 12.47 kV buswork where the loads are the highest.

The highest magnetic field values at the property boundary line and the substation fence line are where the 12.47 kV lines are routed outside on the southeast side of the property. The maximum magnetic field at the fence line is 250 mG and 25 mG at the property boundary line (same for both 69 kV and 115 kV operating systems since the distribution circuit configurations and load do not change).

The transmission line span from the substation to Pole 13/48 has both circuits. At midspan (lowest point of the phase conductor to ground) the maximum electric field is 16 mG and 10 mG for the 69 kV system and 115 kV system respectively. The lower magnetic fields are due to the lower estimated currents for the 115 kV operating system.

The highest magnetic fields for the pole replacement line sections are in due to the line sections with the three distribution circuits. The maximum magnetic field is approximately 50 mG for the span 12/48 -13/48 outside of Lassen Substation.

The range of magnetic fields for the local 12.47 kV distribution lines is from 3 to 22 mG.

Table 1 shows a summary of the calculated electric and magnetic field levels for this assessment. As shown, this summary presents ranges of electric and magnetic field values for each location described.

9.0 POWER FREQUENCY EMF STANDARDS

Presently, there are no EMF standards for the state of California or federal health standards. Although there are no federal health standards in the United States specifically for 60 Hertz magnetic fields, two organizations have developed guidelines: the International Commission on Non-Ionizing Radiation Protection (ICNIRP) [13] and the American Conference of Governmental Industrial Hygienists (ACGIH) [14].

Tables 5 and 6 present a summary of the electric and magnetic field levels of these guidelines respectively. Calculated electric and magnetic field levels at publicly accessible areas in the property and underneath the power lines are below the levels cited within the ICNIRP guideline. With respect to the ACGIH guideline, calculated electric and magnetic field levels at publicly accessible areas are below the levels cited within this guideline, with the exception of one small area. The area directly underneath the 69/115 kV circuits for the span into the proposed substation has unperturbed calculated electric field levels above 1 kV/m, which is above the ACGIH guideline for workers with cardiac pacemakers. However, these calculated electric field levels are unperturbed values, and the presence of the substation fence, the structural steel pole, and any other types of grounded objects in this area may significantly shield the electric field and may reduce field levels below 1 kV/m.

TABLE 5: SUMMARY OF ICNIRP 50/60 HZ EXPOSURE GUIDELINES		
International Commission on Non-Ionizing Radiation Protection Guidelines		
Exposure (50/60 Hz)	**Electric Field**	**Magnetic Field**
Occupational:		
Reference Levels for Time-Varying Fields	8.333 kV/m (8,333 V/m)	4.167 G (4,167 mG)
Current Density for Head and Body	10 mA/m2 (25 kV/m)	10 mA/m2 (5 G)
General Public:		
Reference Levels for Time-Varying Fields	4.167 kV/m (4,167 V/m)	0.833 G (833 mG)
Current Density for Head and Body	2 mA/m2 (5 kV/m) 2 mA/m2	2 mA/m2 (1 G) 2 mA/m2 (1 G)

TABLE 6: SUMMARY OF ACGIH 60 HZ EXPOSURE GUIDELINES	
ACGIH Occupational Threshold Limit Values for 60-Hz EMF	
Electric Field	**Magnetic Field**
Occupational exposures should not exceed:	**Occupational exposures should not exceed:**
25 kV/m	**10 G**
(from 0 Hz to 100 Hz)	**(10,000 mG)**
Prudence dictates the use of protective devices (e.g. suits, gloves, insulation) in fields above 15 kV/m.	
For workers with cardiac pacemakers, maintain exposure at or below 1 kV/m	For workers with cardiac pacemakers, the field should not exceed 1 G (1,000 mG).

In addition, IEEE has published a standard regarding exposure to electromagnetic fields [15]. Table 7 presents a summary of the 60 Hz electric and magnetic field levels for this standard. The calculated magnetic field levels within publicly accessible areas surrounding the proposed substation site are much lower than the levels cited within the IEEE standard.

TABLE 7: SUMMARY OF IEEE 60 HZ EXPOSURE LEVELS	
IEEE Exposure Levels for 60 Hz Electric and Magnetic Fields	
Electric Field	**Magnetic Field**
General Public should not exceed:	**General Public should not exceed:**
5 kV/m	**9.04 Gauss**
(from 1 Hz to 368 Hz)	**(9,040 mG)**
Controlled Environment should not exceed:	**Controlled Environment should not exceed:**
20 kV/m	**27.1 Gauss**
(from 1 Hz to 272 Hz)	**(27,100 mG)**

10.0 EMF MITIGATION

Representatives of the public have expressed concern about possible health effects associated with power frequency electric and magnetic fields. Numerous international scientific organizations and independent regulatory advisory groups have conducted scientific reviews of the EMF research literature. The results of this research are inconclusive and public concern and scientific uncertainty remains regarding the potential health effects of EMF exposure.

In January 1991, the CPUC issued an Order instituting investigation to develop policies and procedures for addressing concerns for potential health effects of magnetic fields from utility facilities. The CPUC formed the California Consensus Group (CCG), a committee of 17 stakeholders representing diverse interests and perspectives, to provide guidance on interim EMF measures which the CPUC might adopt while waiting for resolution of the scientific uncertainties. In March 1992, the CCG issued its report. In part, the report recommended that the CPUC authorize utilities to implement magnetic field reduction techniques if those techniques could be implemented at little or no cost. In November 1993, the CPUC issued Decision 93-11-013 adopting interim policy regarding EMF. California's electric utilities were authorized to implement no- and low-cost (low cost is defined as 4% of the total project cost) field management techniques to reduce EMF levels from new and upgraded electrical facilities if an incremental reduction of at least 15 percent can be achieved. In a decision issued in January 2006 (D.06-01-042), the Commission affirmed its "low cost/no cost" policy for mitigating EMF levels.

Calculated electric and magnetic field levels from the proposed Lassen Substation project were reviewed in conjunction with the policies set forth in CPUC Decision 93-11-013.

10.1 Electric Fields

For electric fields, the area with the highest calculated field increase occurs where the 69/115 kV circuits are tapped and drop into the Lassen Substation. However, the presence of the substation fence and other nearby objects will shield the electric field within their immediate vicinity. Outside of the substation, calculated electric field levels are below the standards (except underneath the future 115 kV transmission circuit span into the substation). A no-cost/low-cost mitigation option would be to extend the proposed substation fence line on the west side of the substation parallel along the span to Pole 13A/48 a distance of approximately 20 feet on each side of the centerline, which would restrict public access from the area where the 115 kV circuit goes into the substation. If this action were taken, then the calculated electric field for publicly accessible areas would be reduced from 2.25 kV/m to below 0.7 kV/m (a reduction of about 321.4 percent).

10.2 Magnetic Fields

For magnetic fields, the main source of fields is the presence of the existing overhead power lines, and in particular, the distribution underbuild. Magnetic fields from the proposed substation equipment are reduced to background levels at the edge of the proposed substation fence.

No-Cost Magnetic Field Mitigation

Since the main source of magnetic fields in the area near the proposed substation is due to the presence of the 12.47 kV distribution underbuild, no changes to the proposed substation design are recommended. If the load were perfectly balanced, then magnetic field levels would be reduced (since the magnetic field attenuation rate would be increased as a function of distance away from the distribution line – from the inverse of the distance for unbalanced loads to the inverse of the distance squared for balanced loads).

However, it is not feasible to attempt to reduce the small percentage of unbalanced load which exists on this distribution line and achieve perfectly balanced loading.

Low-Cost Magnetic Field Reduction
The height of the poles supporting the 69/115 kV and 12.47 kV circuits are being increased in the area of the pole replacements which would reduce the calculated magnetic fields from the transmission line. But since the calculated magnetic field is primarily due to an unbalanced distribution loading, the field attenuation is characterized as the inverse of the distance, and additional height increase may be required to achieve a moderate field reduction.

The magnetic fields are below the standards so that additional mitigation is not warranted.

11.0 SUMMARY AND CONCLUSIONS

For the 69 kV transmission line scenario, in the pole replacement section, the highest calculated electric field of approximately 0.25 kV/m occurs in the span between Poles 13A/48 and 13/48. For the 115 kV transmission line scenario, in the pole replacement section, the highest calculated electric field of about 0.4 kV/m occurs in the span between Poles 13A/48 and 13/48. At the location of the property boundary line where the two transmission circuits enter the substation, the maximum calculated electric field at the pole outside the substation is 0.7 kV/m for the 69 kV scenario and 2.25 kV/m for the 115 kV scenario. The calculated electric field values are unperturbed values and do not include the effects of electric field reduction due to the presence of shielding objects, such as the substation fence, trees, bushes, and other objects. The presence of these types of objects will shield the electric field within their immediate vicinity.

For the magnetic fields, the calculations show that the dominant sources of magnetic fields are due to the presence of the unbalanced currents on the 12.47 kV distribution lines. In the pole replacement section, the highest calculated magnetic field of approximately 50 mG occurs for the span 12/48 - 13/48 outside of Lassen Substation. At the southeast side of the property boundary line, the maximum magnetic field level is approximately 250 mG which is due to the distribution lines. Outside of and away from the proposed substation property, the calculated magnetic field remains virtually unchanged between the existing and proposed substation configurations. Inside the substation magnetic fields are predicted to be a maximum of approximately 2,200 mG.

The results of these calculations are summarized in Table 1.

Calculated electric and magnetic levels are below the guidelines developed by ICNIRP and IEEE for publicly accessible areas. With respect to the guidelines developed by the ACGIH, calculated electric and magnetic field levels at publicly accessible areas are below the levels cited, with the exception of one small area. This area directly underneath the 69 kV circuit as it drops down into the proposed substation has unperturbed calculated electric field levels above 1 kV/m, which is above the ACGIH guideline for workers with cardiac pacemakers. However, these calculated electric field levels are unperturbed values, and the presence of the substation fence, the structural steel pole, and any other types of grounded objects in this area will shield the electric field within their immediate vicinity and may reduce field levels below 1 kV/m (the amount of field reduction would depend upon the quantity, types, size, and other characteristics of these potential shielding objects).

For electric field mitigation, the area with the highest calculated field increase occurs for the 69/115 kV transmission line span into the substation. A no-cost/low-cost mitigation option would be to extend the proposed fence line on the west side of the substation along the span to Pole 13A/48 a distance of approximately 20 feet on both sides of the center line which would restrict public access from this area of higher electric fields. In addition, the presence of the extended substation fence would also provide some electric field shielding within its immediate vicinity and would therefore reduce electric fields within this area.

For magnetic field mitigation, calculated levels from the proposed substation equipment are reduced to background levels at the edge of the proposed substation fence. The main source of magnetic field is the presence of the existing overhead power lines, and in particular, the distribution underbuild. Therefore, no changes to the existing power line configuration or proposed substation design for magnetic field mitigation are recommended.

12.0 REFERENCES

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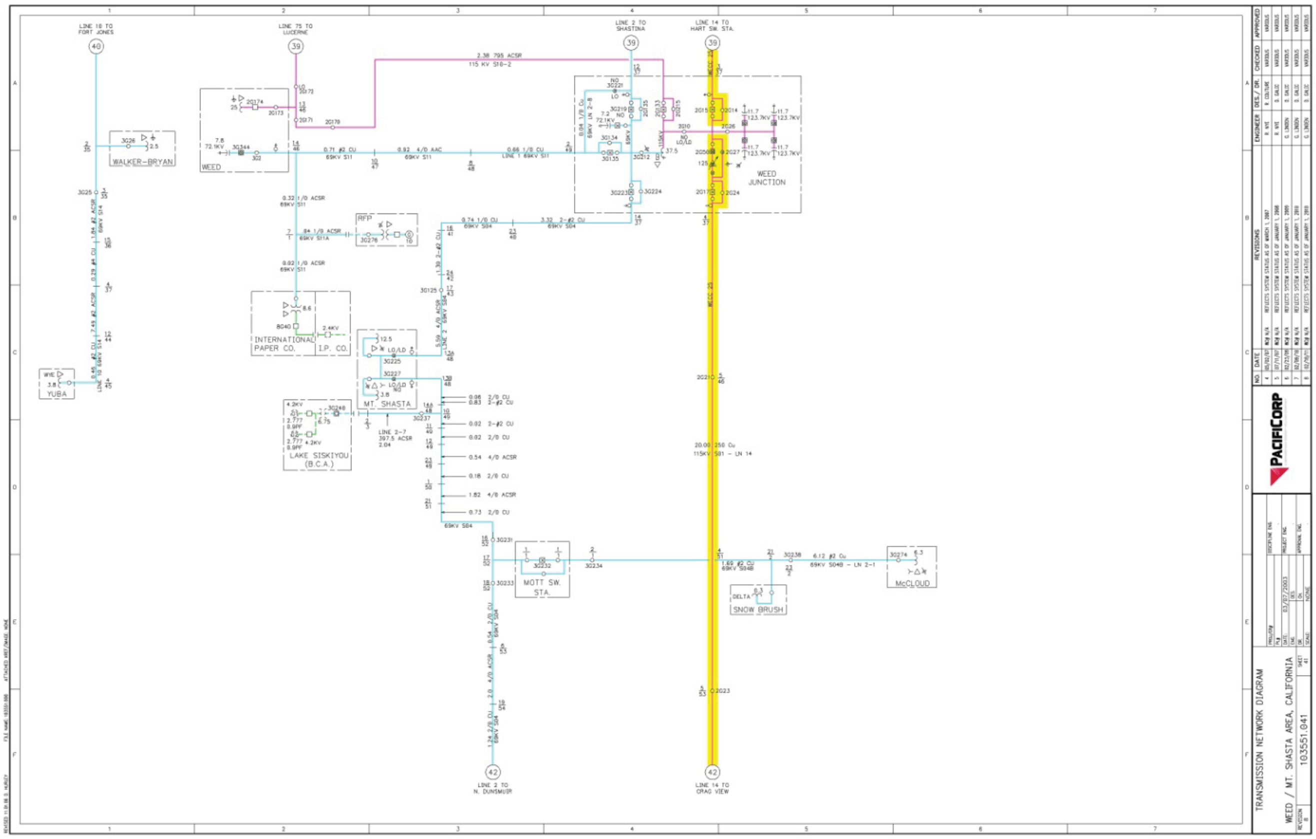
5) Biological Effects of Electric and Magnetic Fields of Extremely Low Frequency, A.R. Sheppard and M. Eisenbud, New York University Medical Center, 1977.
6) "Fields From Electric Power", Carnegie Mellon University, Department of Engineering and Public Policy, Pittsburgh, PA, 1995.
7) "Household Appliance Magnetic Field Survey", U.S. Naval Electronic Systems Technical Report No. EO6549-3, Illinois Institute of Technology Research Institute, Chicago, March,1984.
8) Silva, J.M., Hummon, N.P., Rutter, D.A., Hooper, H.C., "Power Frequency Magnetic Fields in the Home", IEEE Transactions on Power Delivery, Vol. PWRD-4, No. 1, pp. 465-478, January, 1989.
9) "Survey of Residential Magnetic Field Sources", L.E. Zaffanella, Final Report TR-102759 (2 Volumes), Prepared by the High Voltage Transmission Research Center for the Electric Power Research Institute, 1993.
10) "Environmental Field Surveys", EMF RAPID Program – Engineering Project #3, Final Report, L.E. Zaffanella, Prepared for Lockheed Martin Energy Systems, Inc., April 1996.
11) "Electric and Magnetic Field Management Reference Book", First Edition, TR-114200, EPRI, Palo Alto, CA: 1999.
12) "IEEE Standard Procedures for Measurement of Power Frequency Electric and Magnetic Fields from AC Power Lines", IEEE Standard 644-1994, Institute of Electrical and Electronics Engineers, 1994.
13) "Guidelines for Limiting Exposure to Time-Varying Electric, Magnetic, and Electromagnetic Fields (Up To 300 Hz)", International Commission on Non-Ionizing Radiation Protection (ICNIRP), Health Physics, 74: 494-522, 1998.
14) Threshold Limit Values for Chemical Substances and Physical Agents", American Conference of Governmental Industrial Hygienists (ACGIH), Cincinnati, ISBN 1-88-2417-23-2, 1998.
15) "IEEE Standard for Safety Levels with Respect to Human Exposure to Electromagnetic Fields, 0 – 3 kHz", IEEE Std C95.6-2002, Institute of Electrical and Electronics Engineers, 2002.

APPENDIX A: DESIGN AND LOAD INFORMATION

Weed Jct – Mt Shasta Transmission Network Diagram




Lassen Substation
Legend
Project Beginning/Ending
Pole
Proposed Substation Location
Parcel Boundary
0 375 750 1,500 2,250 3,000
Feet
POWER ENGINEERS
PACIFIC POWER
A DIVISION OF PACIFICORP
N
S
E
W
Start of Project
End of Project
Proposed Lassen Substation Site
Mount Shasa Substation
Mercy Medical Center
Sisson Elementary School
Mount Shasta Elementary School
Mount Shasta
Sisson Museum
Mount Shasta State Fish Hatchery
Browns Lake
Chateau Shasta Mobile Home Park
Pioneer
5
13/47
14/47
15/47
16/47
17/47
18/47
19/47
20/47
21/47
22/47
23/47
24/47
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14A/48
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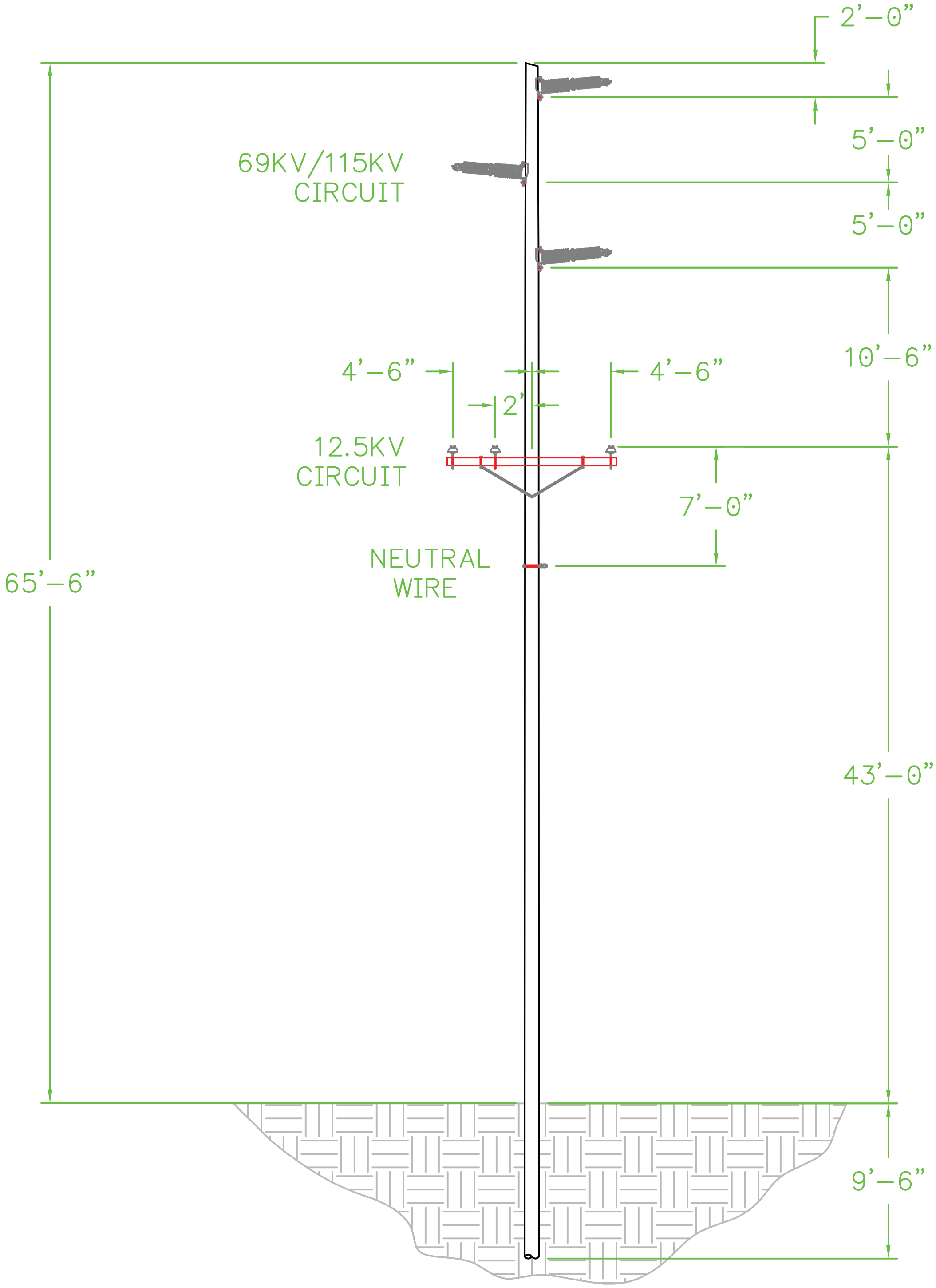
8/49
9/49
10/49



STRUCTURE 21/48 & 22/48

NO.	DATE	WO# REVISIONS	ENGINEER	DES./ DR.	CHECKED	APPROVED

TRANSMISSION			
DISCIPLINE ENG.	PROJ/ER#	PL# 668002	
	DATE: 09/23/2010		
PROJECT ENG.	ENG:	DES: D. NEWCOMER	
	DR: D. NEWCOMER	CH:	
APPROVAL ENG.	SCALE: 1"=10'		

LINE 2
69 KV TRANSMISSION LINE
LASSEN SUBSTATION
TF100 TANGENT STR WITH 1 DIST. CIRCUIT

SHEET 1 OF 1 | STRUCTURE EXHIBIT #1 | REVISION 0

PACIFICORP
A MIDAMERICAN ENERGY HOLDING COMPANY

REVISED 11.01.06 D. HURLEY CAD NO.:

Transmission and Distribution Line Loading Information

From: allison.carver@powereng.com [mailto:allison.carver@powereng.com]
Sent: Thursday, June 09, 2011 2:56 PM
To: Taylor, Scott
Cc: kbell@powereng.com
Subject: Lassen Substation EMF -- questions

Hi Scott,

Our engineer who is in charge of the EMF section has some questions that I don't have the answers to, and I'm hoping you or your engineers can help us out. Since some of his questions are referring to the Lassen Substation General Plan you sent to me, I'm including that as an attachment. I have attached a new sketch

1. What is the operation of the Lassen Substation i.e. is it a looped system with power flow through the substation from the north to the south or is there power from each direction? Transmission operation will not be looped, will be normally open just south of Lassen, and power will normally be supplied to Lassen from the north.

2. What are the ratings of the transformers? The substation will have an 115kV-12.5kV, 15/20/25MVA transformer

3. Are there two distribution lines from the substation? There will be three distribution lines from Lassen Sub, two existing and one new.

4. Does the distribution leave the substation underground to the first pole? It is expected that the distribution will leave the sub above ground to the first pole to avoid disturbance of the wetlands

5. If there are two distribution lines, are they on two separate lines from the substation? There will be three distribution lines, each on separate lines from the substation.

6. Does the diagram show two sets of shield wires connected to poles on the east side of the substation? The transmission line at Lassen Sub does not presently have a shield wire and a shield is not planned for the future.

7. Does the blue line in the diagram represent the property boundary? What is the fence area for the substation? See new diagram

8. What are the maximum loads for the transmission and distribution lines? The maximum load that will occur on the transmission line for many decades will be the rating of the new Lassen transformer, which would be 25 MVA summer and 30 MVA winter, operating at 69 kV. The maximum load on each feeder will be 10.3 MVA operating at 12.5 kV.

Line 2 Pole Replacements Due to Change in Distribution Underbuild

- The **8** structures from 19/47-3/48 have a change in the distribution underbuild from 12.47 kV 336 ACSR single-circuit to 12.47 kV 336 ACSR top and 477 AAC bottom double-circuit. The added loading from the 2nd circuit would require a higher pole class as the existing poles in this section appear to be Class-2 and Class-3. In addition, the existing pole lengths are not sufficient in this section of line.

- The **6** structures from 3/48-9/48 have a change in distribution from 12.47 kV 556 AAC top and 4.16kv 1/0 CU bottom double-circuit to 12.47 kv 556 AAC top and 12.47 kV 477 AAC bottom double-circuit. The increase in wire size on the second circuit of distribution will cause the wire to sag more which will require more clearance as well as add more loads on the poles. The current Class-2 poles are not likely to be adequate for meeting California Heavy NESC load requirements.

- The **5** structures from 9/48-13A/48 have a change in distribution from 12.47 kV 556 AAC top, 4.16 kV 1/0 CU center, and 4.16 kV 2/0 CU bottom triple circuit distribution underbuild; to 12.47 kV 556 AAC top and 12.47 kV 477 AAC bottom double-circuit. Although there will be one less circuit on the line, there will be an increase in wire size on the new lower circuit and with CL-2 poles the loading would still likely exceed California Heavy NESC load requirements.

- The **5** structures from 13A/48-16/48 have a change in distribution from 12.47 kV 1/0 CU single-circuit distribution to 12.47 kV 477 AAC top, 12.47 kV 477 AAC bottom double-circuit. The added loading from the 2nd circuit would require a higher pole class as the existing poles in this section appear to be Class-2 and Class-3. In addition, the existing pole lengths are not sufficient in this section of line.

- The **12** structures from 16/48-2A/49 have a change in distribution from 12.47 kV 1/0 CU single-circuit to 12.47 kV 477 AAC single circuit. The increase in wire size will cause the wire to sag more which would likely require more clearance as well as add more loads on the poles. The current Class-2 poles are not likely to be adequate for meeting California Heavy NESC load requirements.

The total number of poles to be replaced is actually looking to be **36**.

APPENDIX B: ELECTRIC AND MAGNETIC FIELD CONTOUR AND PROFILE PLOTS

Electric Fields – 69 kV

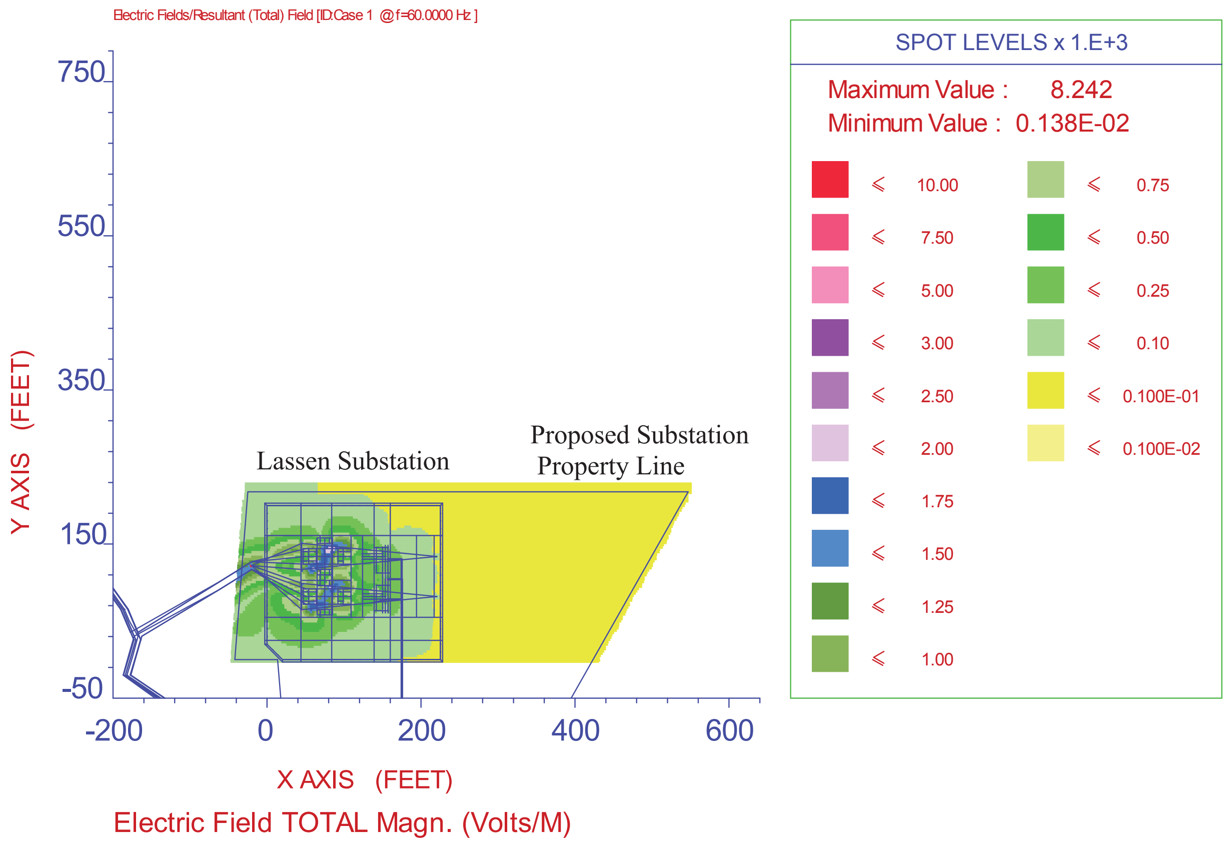


Figure 5: Calculated Electric Field Spot Contour Map for North Portion of Lassen Substation for Existing 69 kV System

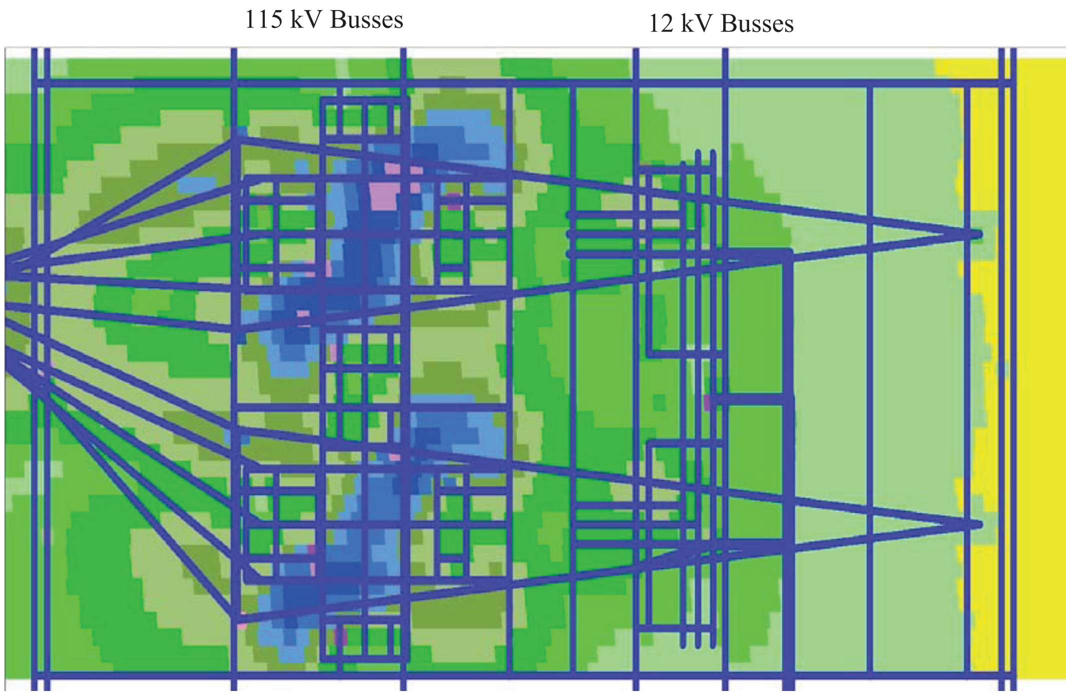


Figure 6: Calculated Electric Field Spot Contour Map for Expanded View of Lassen Substation for Existing 69 kV System

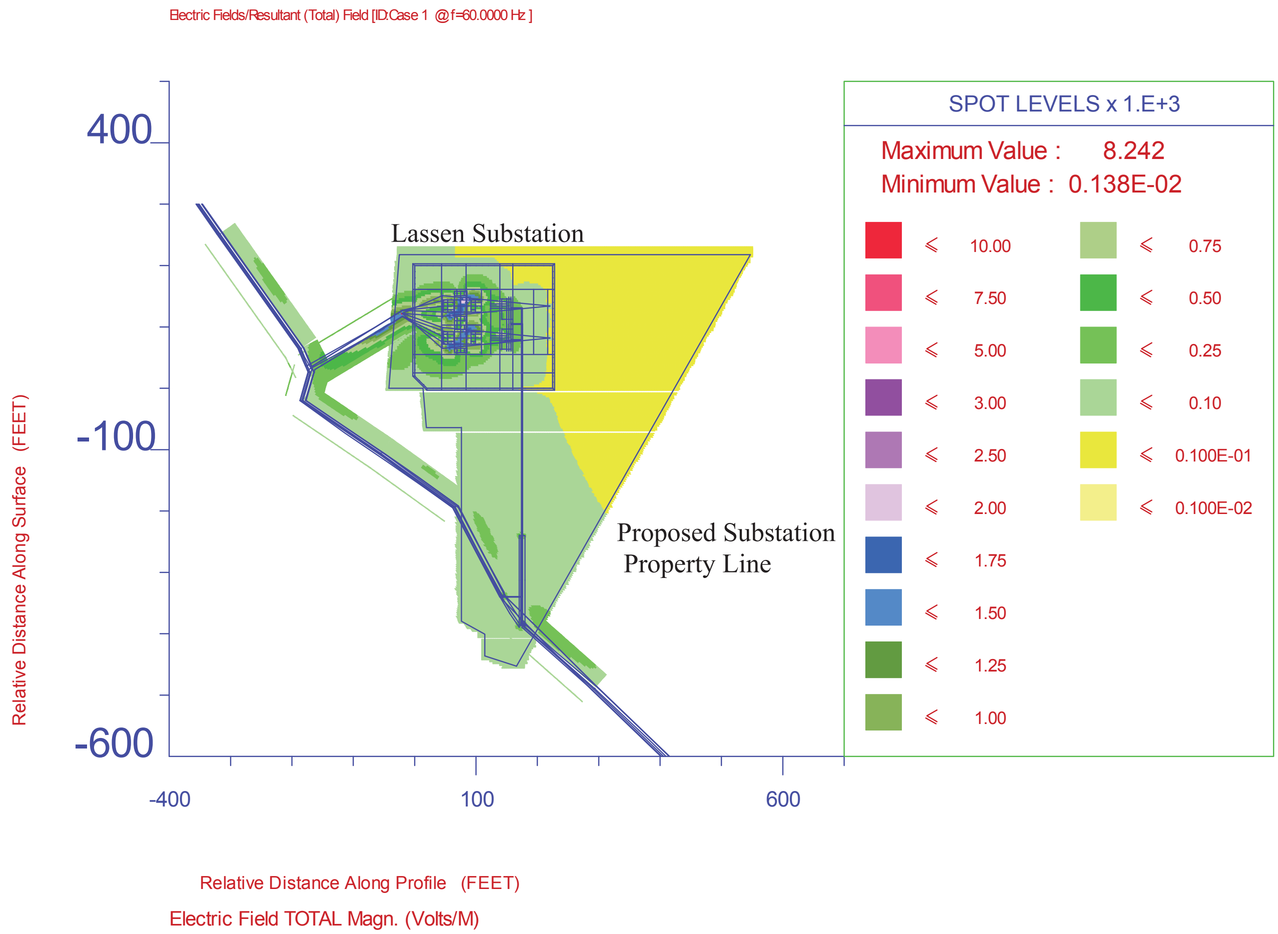


Figure 7: Calculated Electric Field Spot Contour Map for Lassen Substation Property and Transmission/Distribution Lines in Vicinity to the Substation for Existing 69 kV System

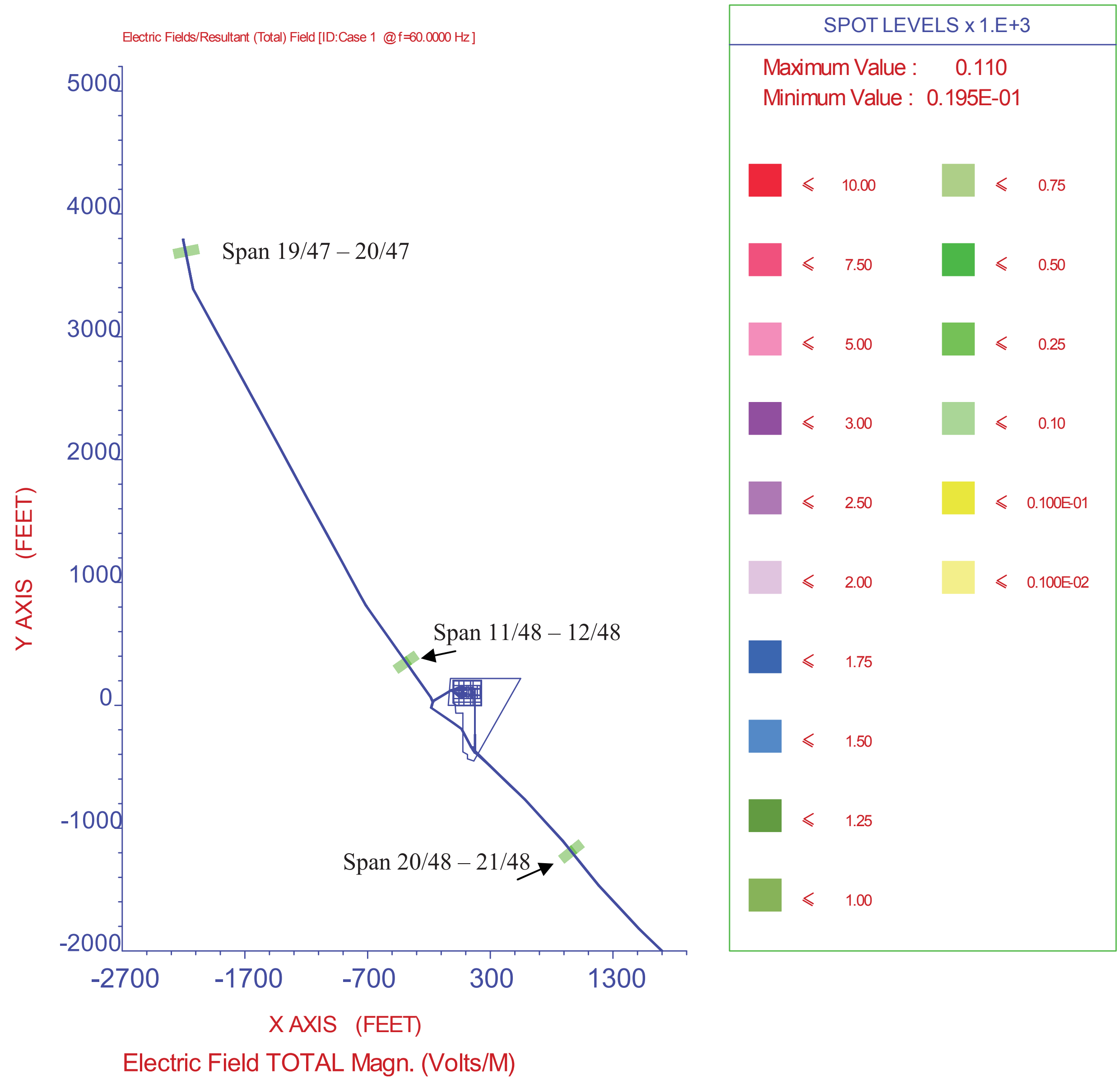


Figure 8: Calculated Electric Field Spot Contour Map for Profiles at Selected Locations of Transmission/Distribution Line Route for Existing 69 kV System

Electric Fields – 115 kV

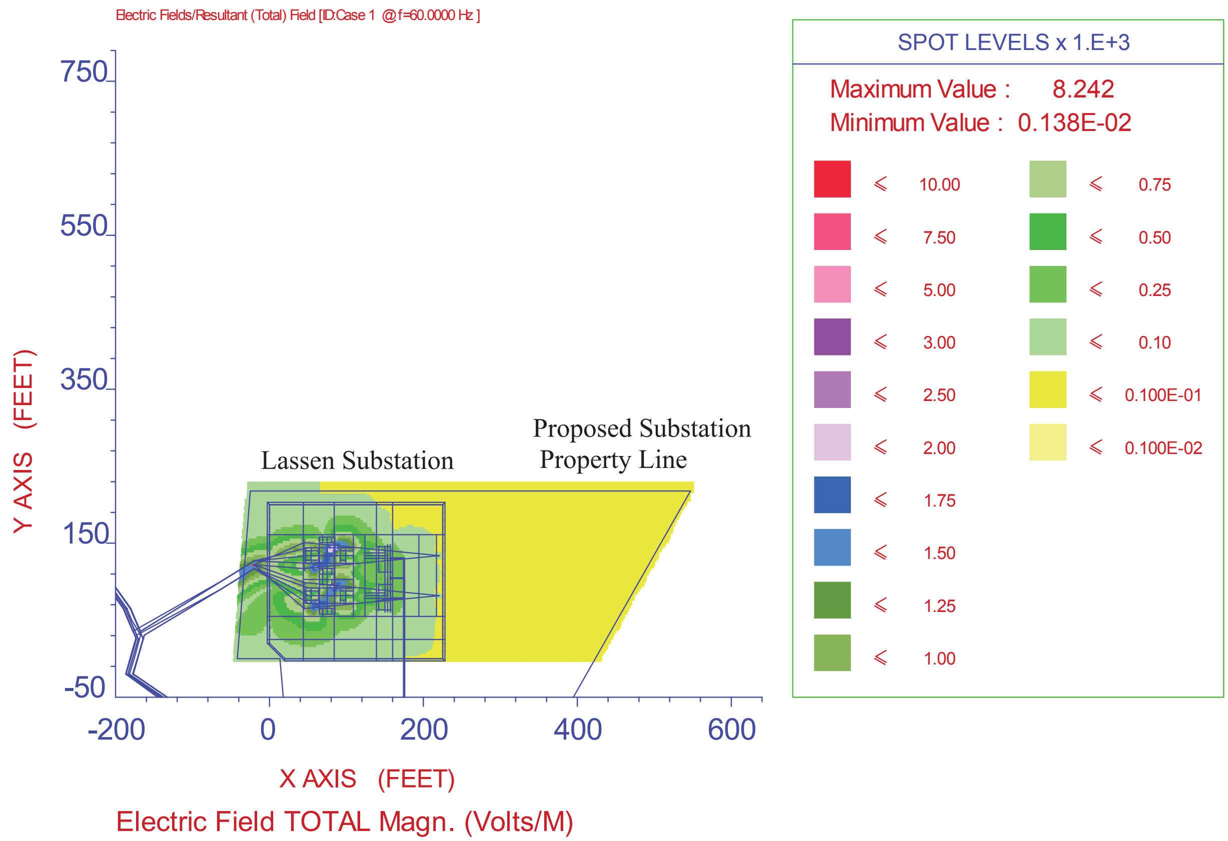


Figure 9: Calculated Electric Field Spot Contour Map for North Portion of Lassen Substation for Future 115 kV System

Figure 10: Calculated Electric Field Spot Contour Map for Expanded View of Lassen Substation for Future 115 kV System

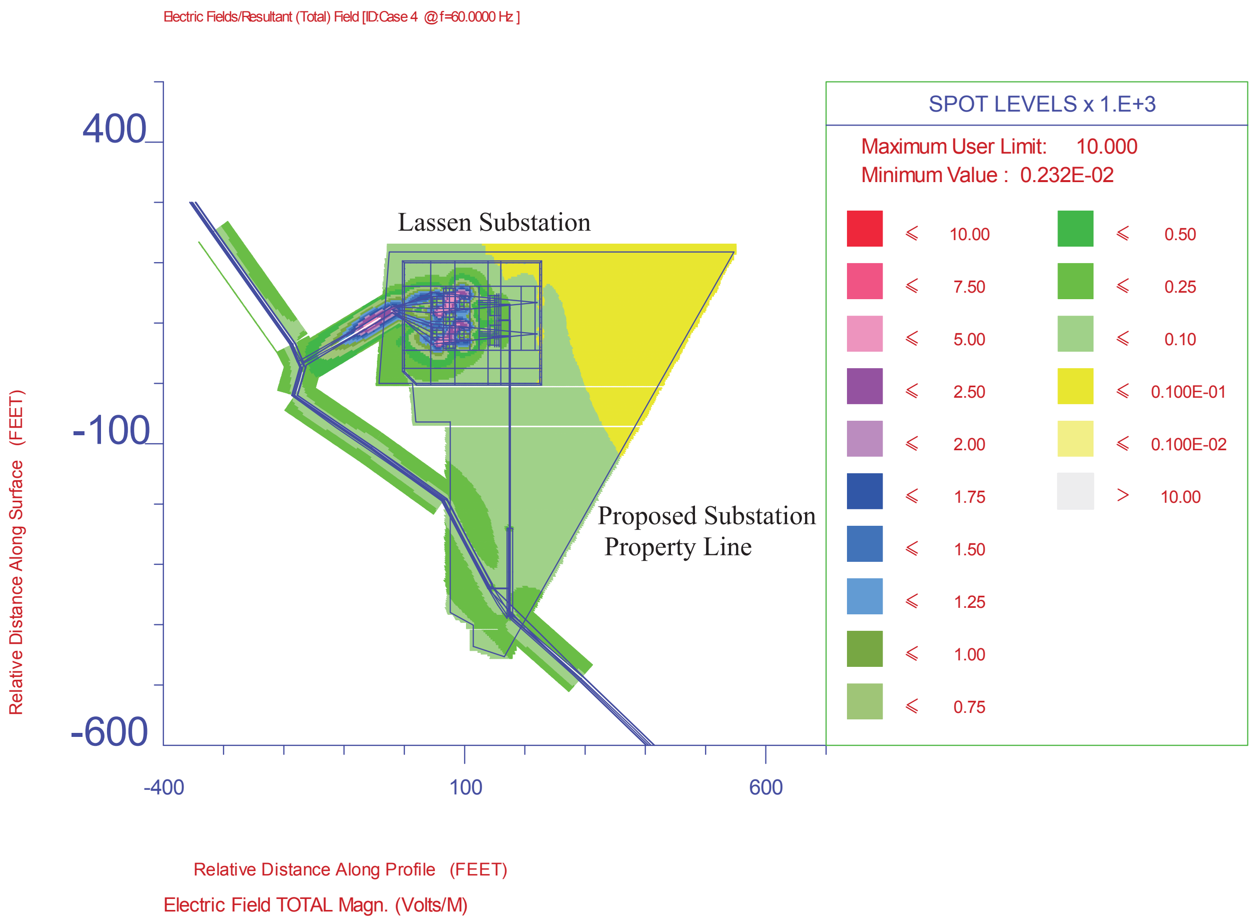


Figure 11: Calculated Electric Field Spot Contour Map for Lassen Substation Property and Transmission/Distribution Lines in Vicinity to the Substation for Future 115 kV System

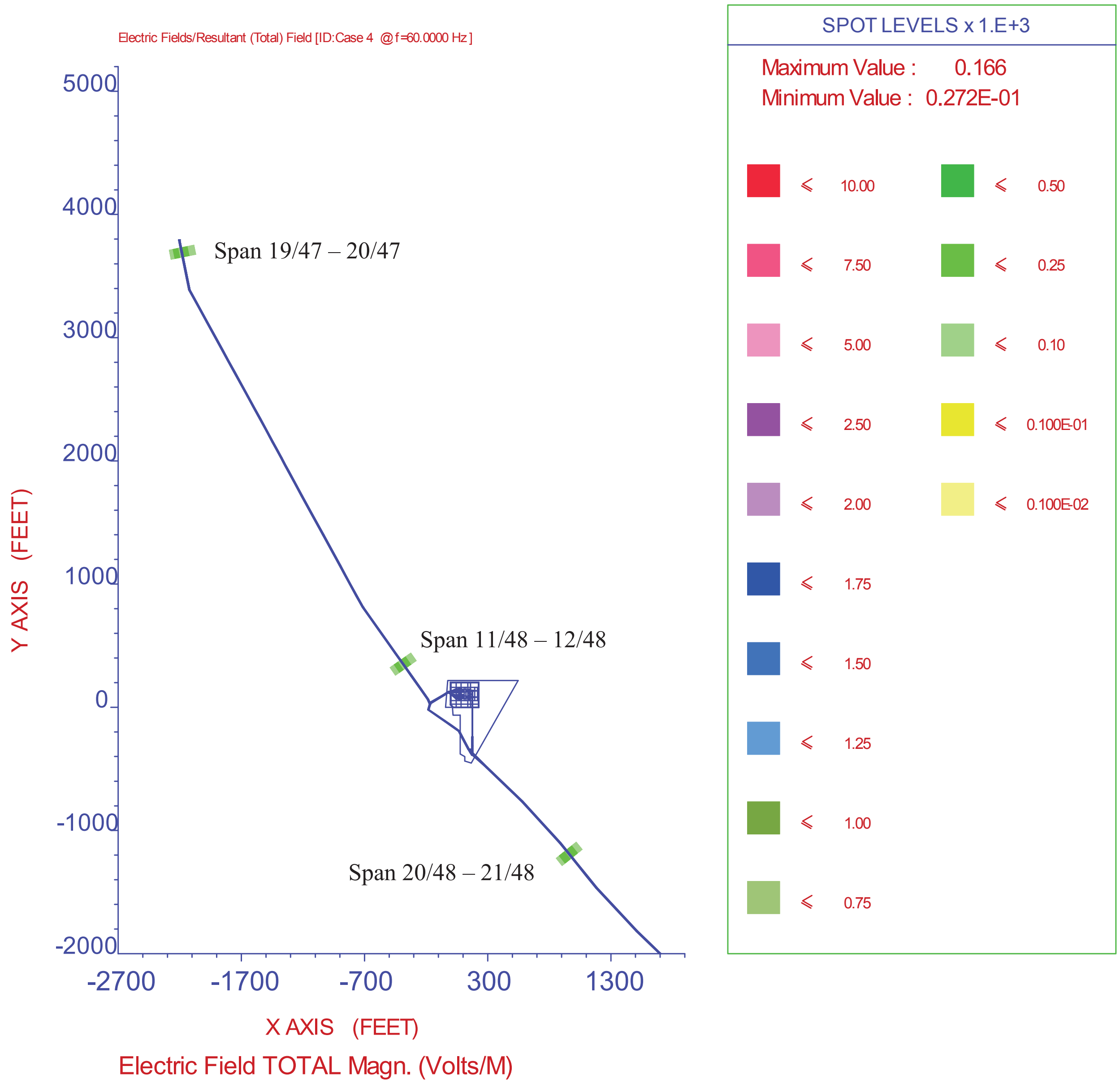


Figure 12: Calculated Electric Field Spot Contour Map for Profiles at Selected Locations of Transmission/Distribution Line Route for Future 115 kV System

Magnetic Fields – 69 kV

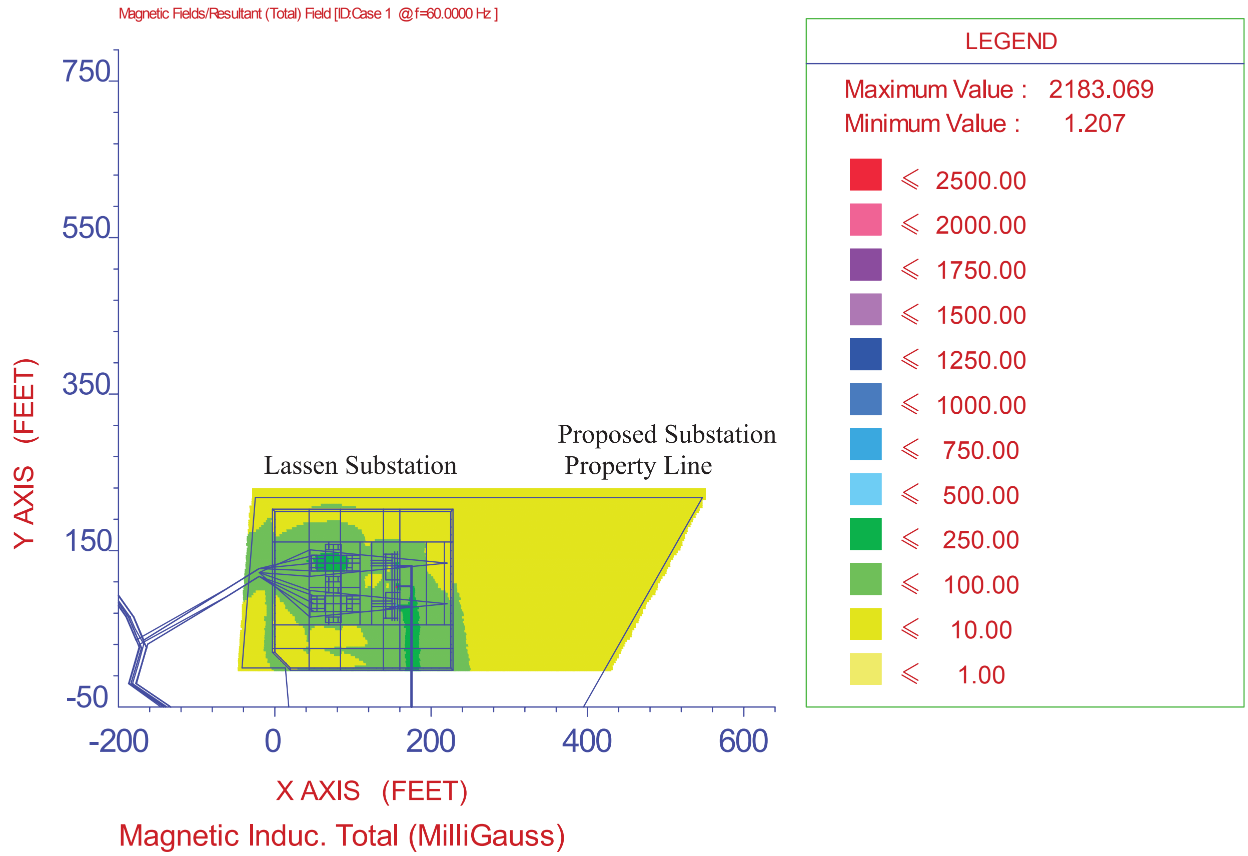


Figure 13: Calculated Magnetic Field Spot Contour Map for North Portion of Lassen Substation for Existing 69 kV System

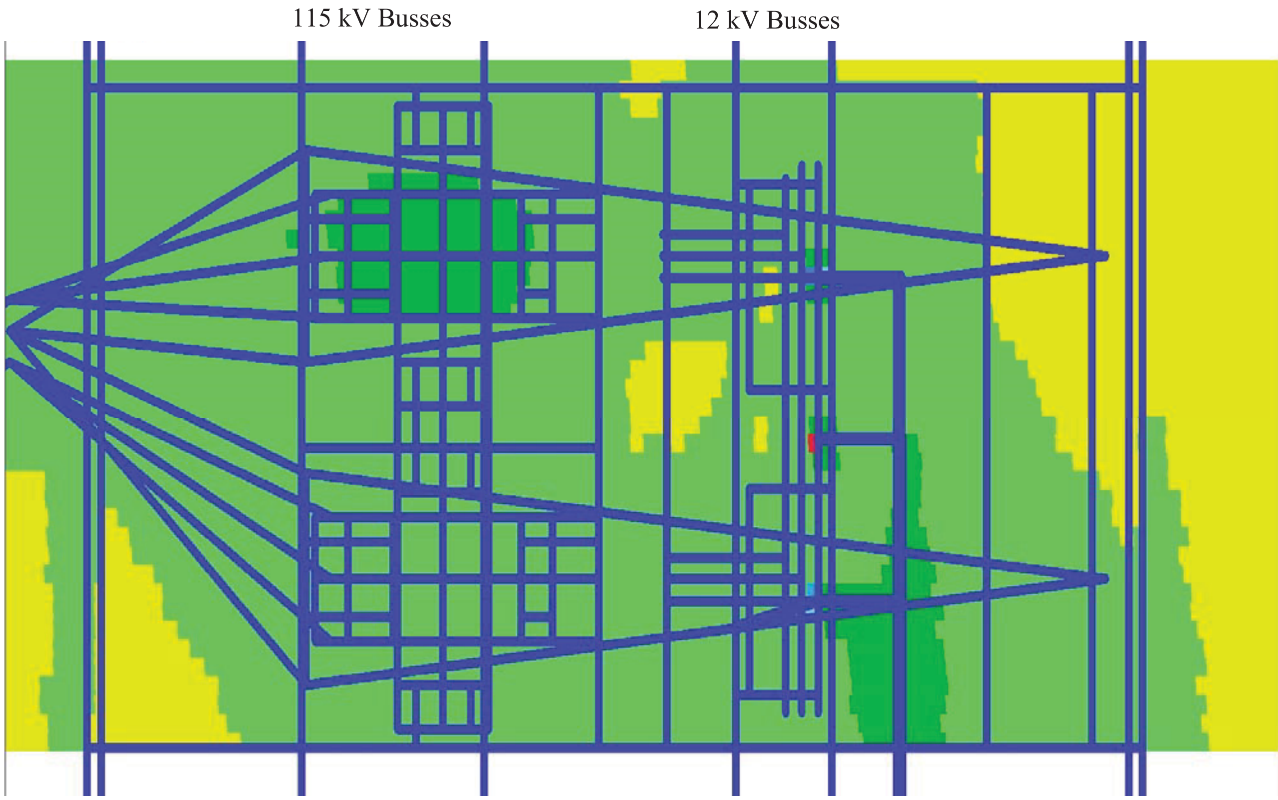


Figure 14: Calculated Magnetic Field Spot Contour Map for Expanded View of Lassen Substation for Existing 69 kV System

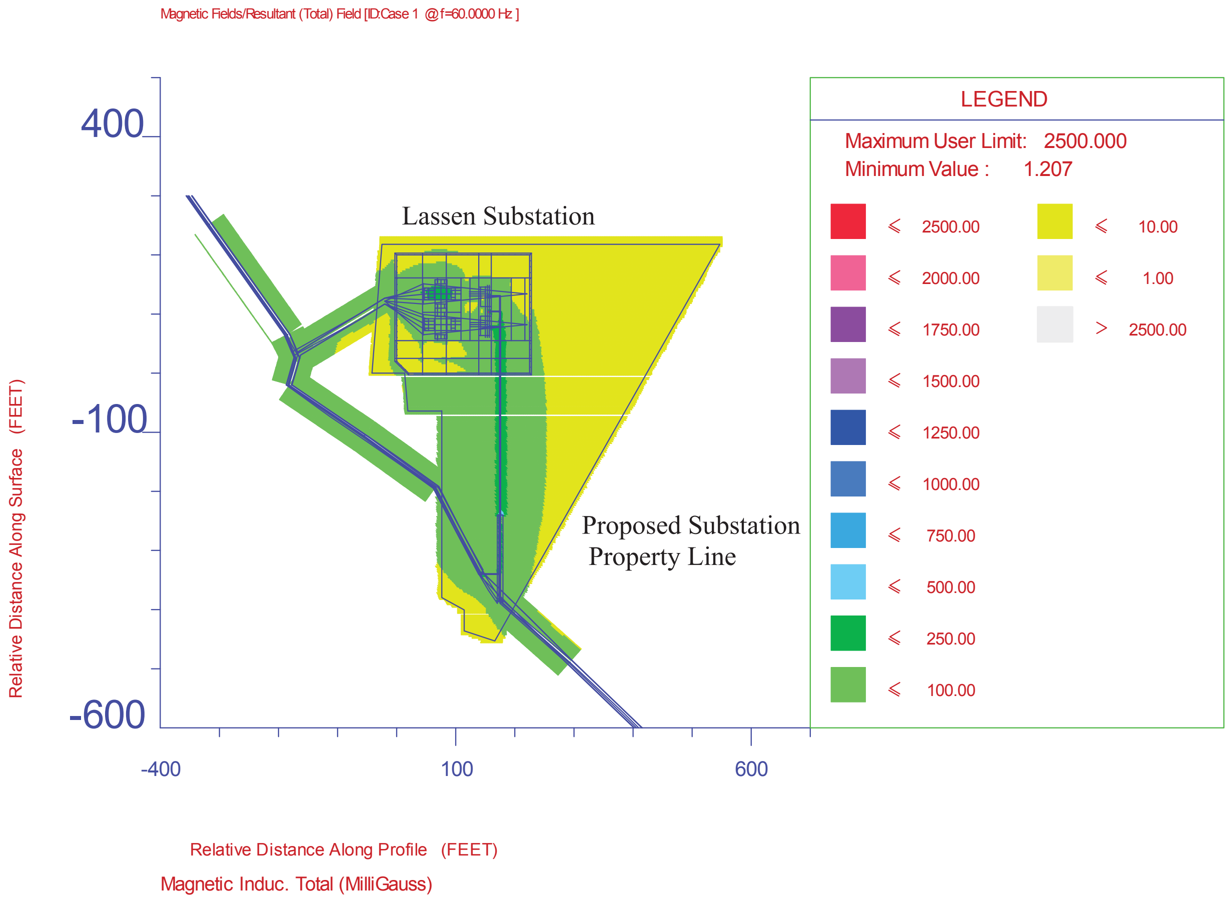


Figure 15: Calculated Magnetic Field Spot Contour Map for Lassen Substation Property and Transmission/Distribution Lines in Vicinity to the Substation for Existing 69 kV System

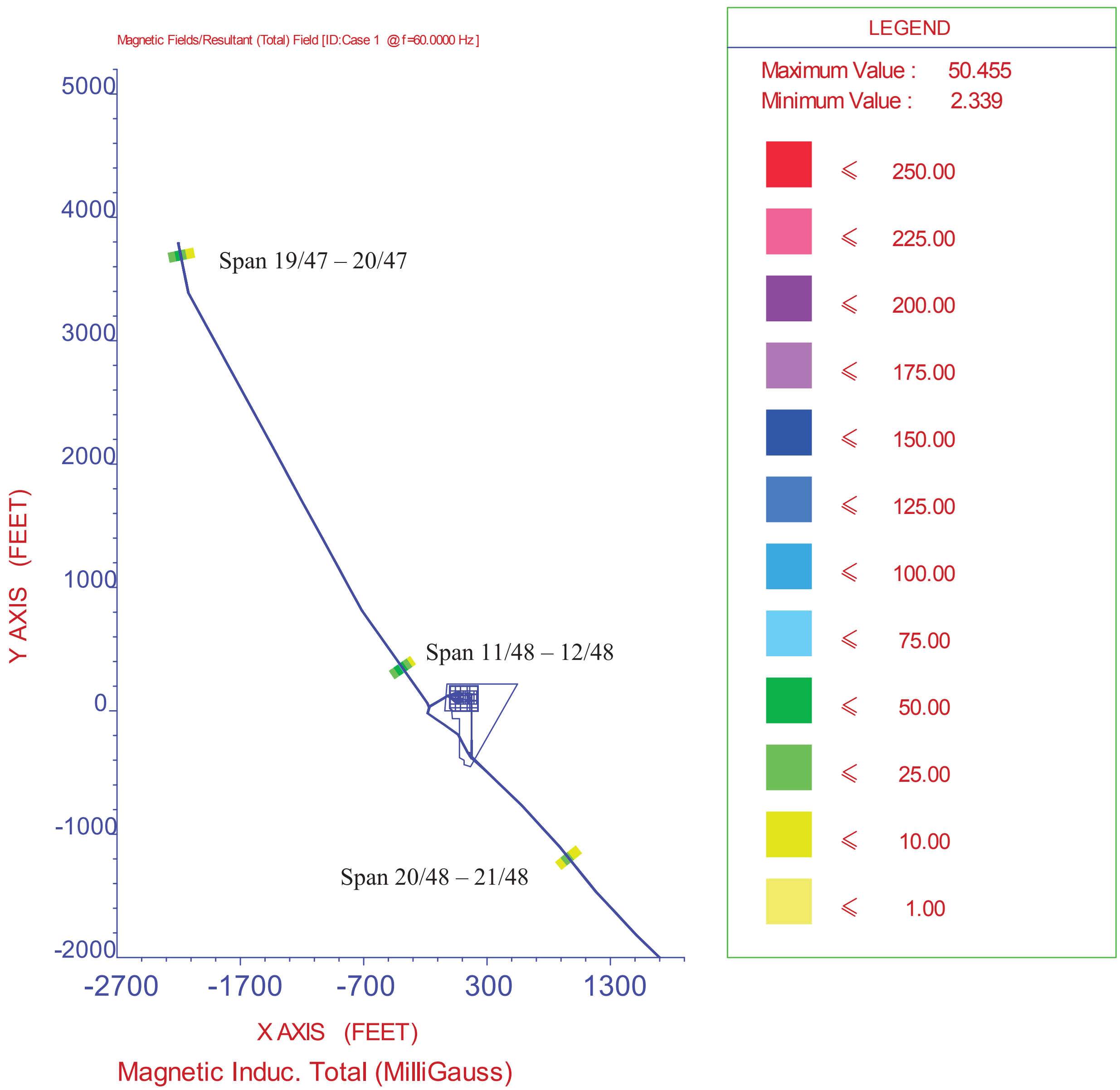


Figure 16: Calculated Magnetic Field Spot Contour Map for Profiles at Selected Locations of Transmission/Distribution Line Route for Existing 69 kV System

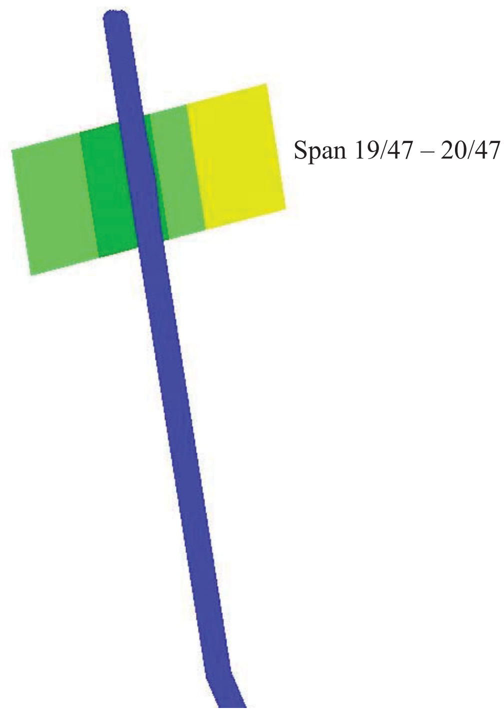


Figure 17: Calculated Magnetic Field Spot Contour Map for Profiles at Span 19/47 – 20/47 for Existing 69 kV System

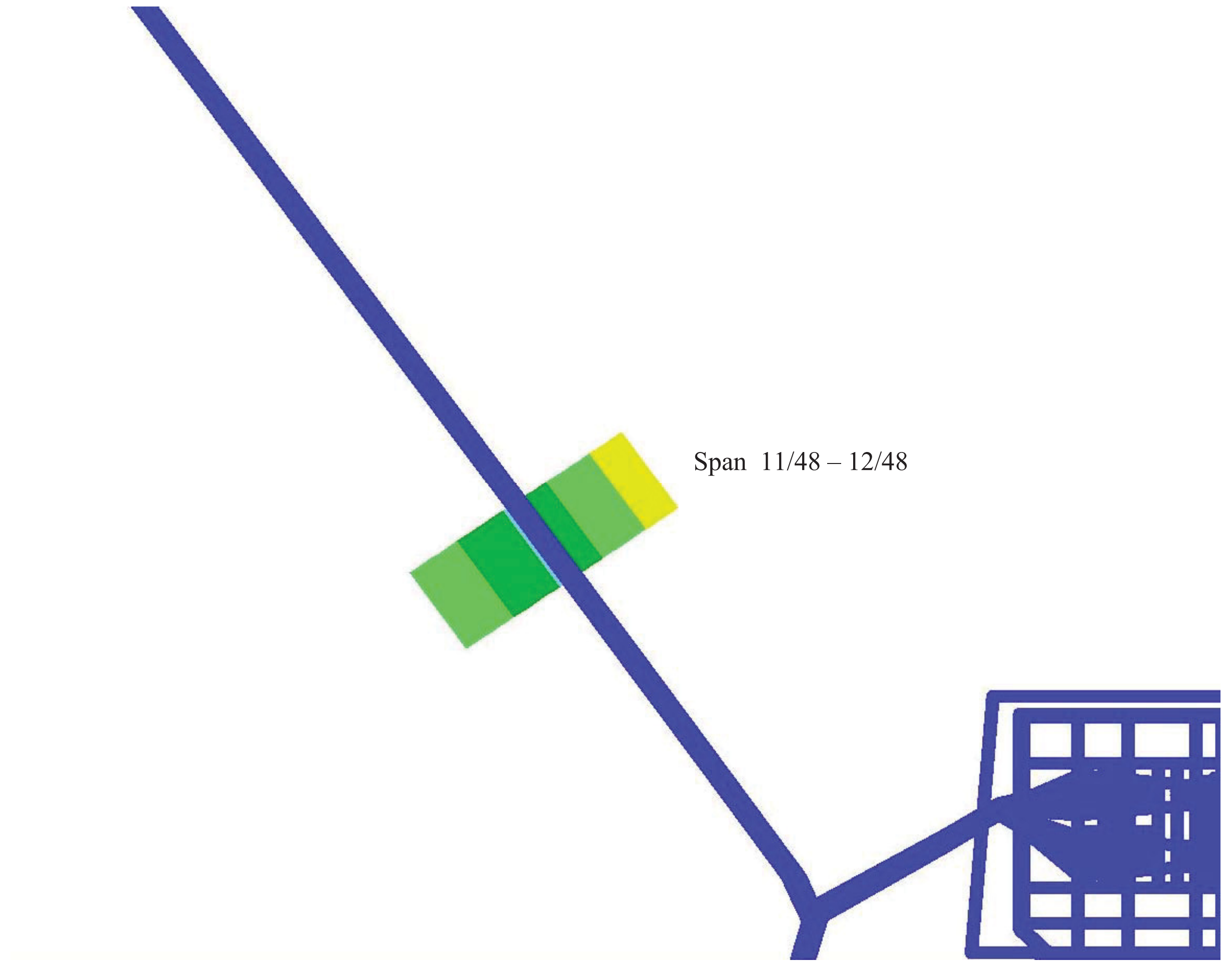


Figure 18: Calculated Magnetic Field Spot Contour Map for Profiles at Span 11/48 – 12/48 for Existing 69 kV System

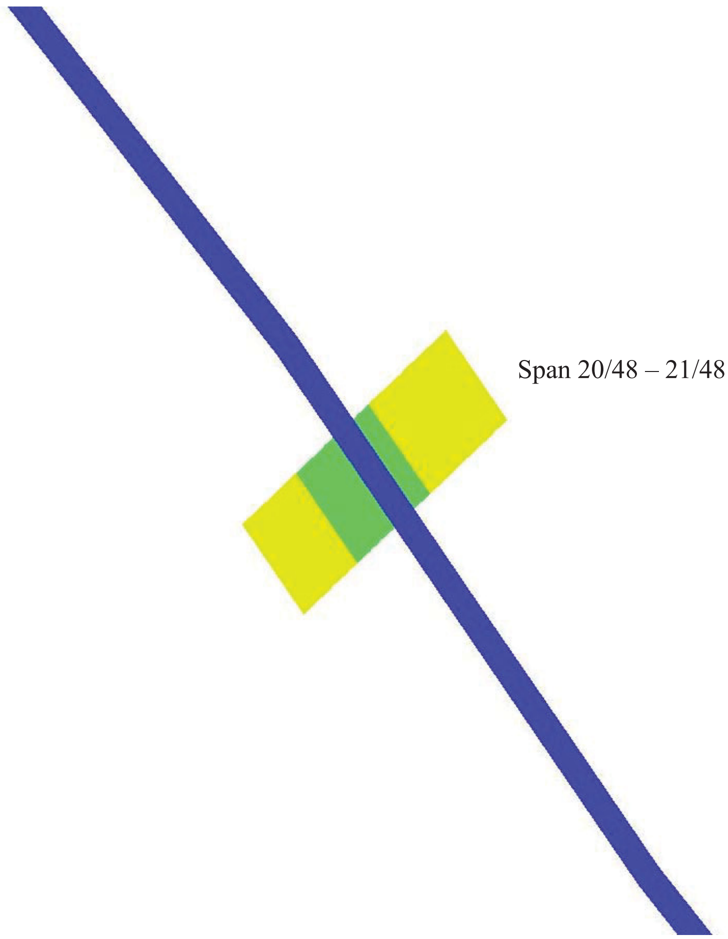


Figure 19: Calculated Magnetic Field Spot Contour Map for Profiles at Span 20/48 – 21/48 for Existing 69 kV System

Magnetic Fields – 115 kV

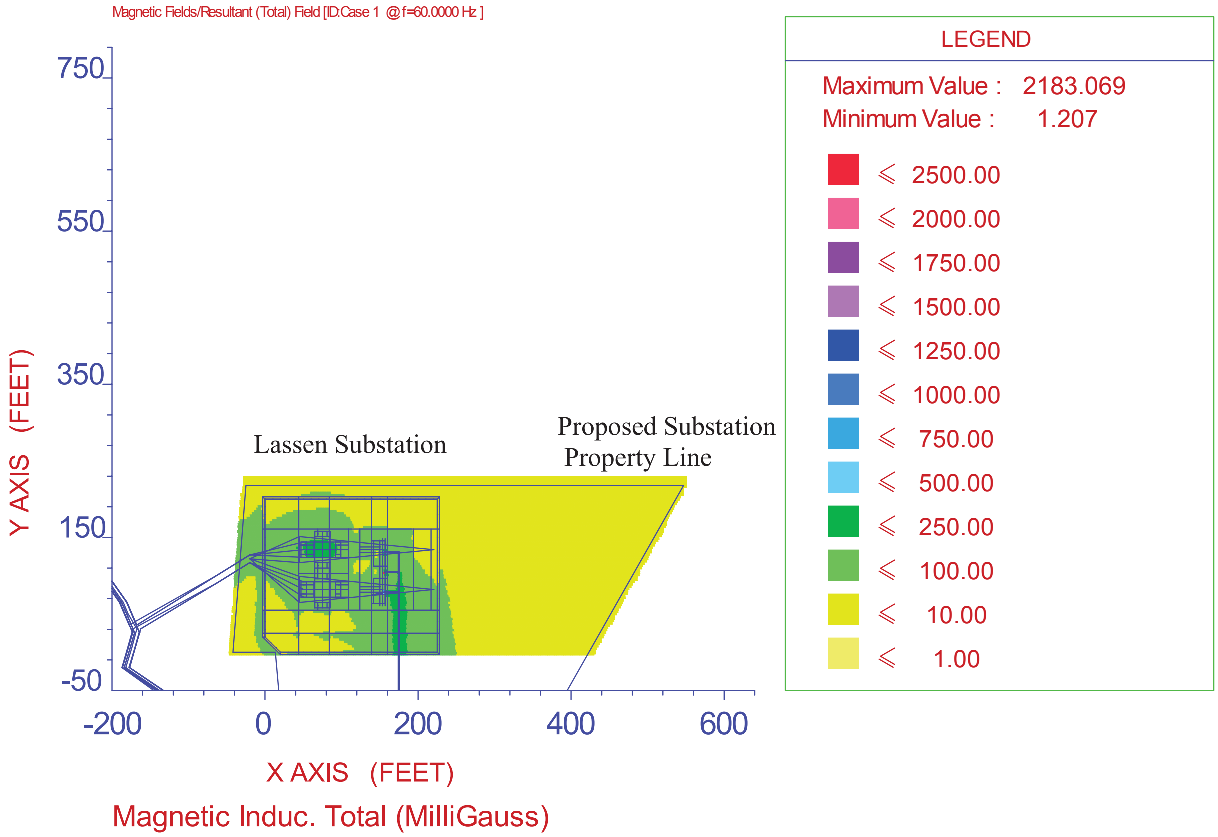


Figure 20: Calculated Magnetic Field Spot Contour Map for North Portion of Lassen Substation for Future 115 kV System

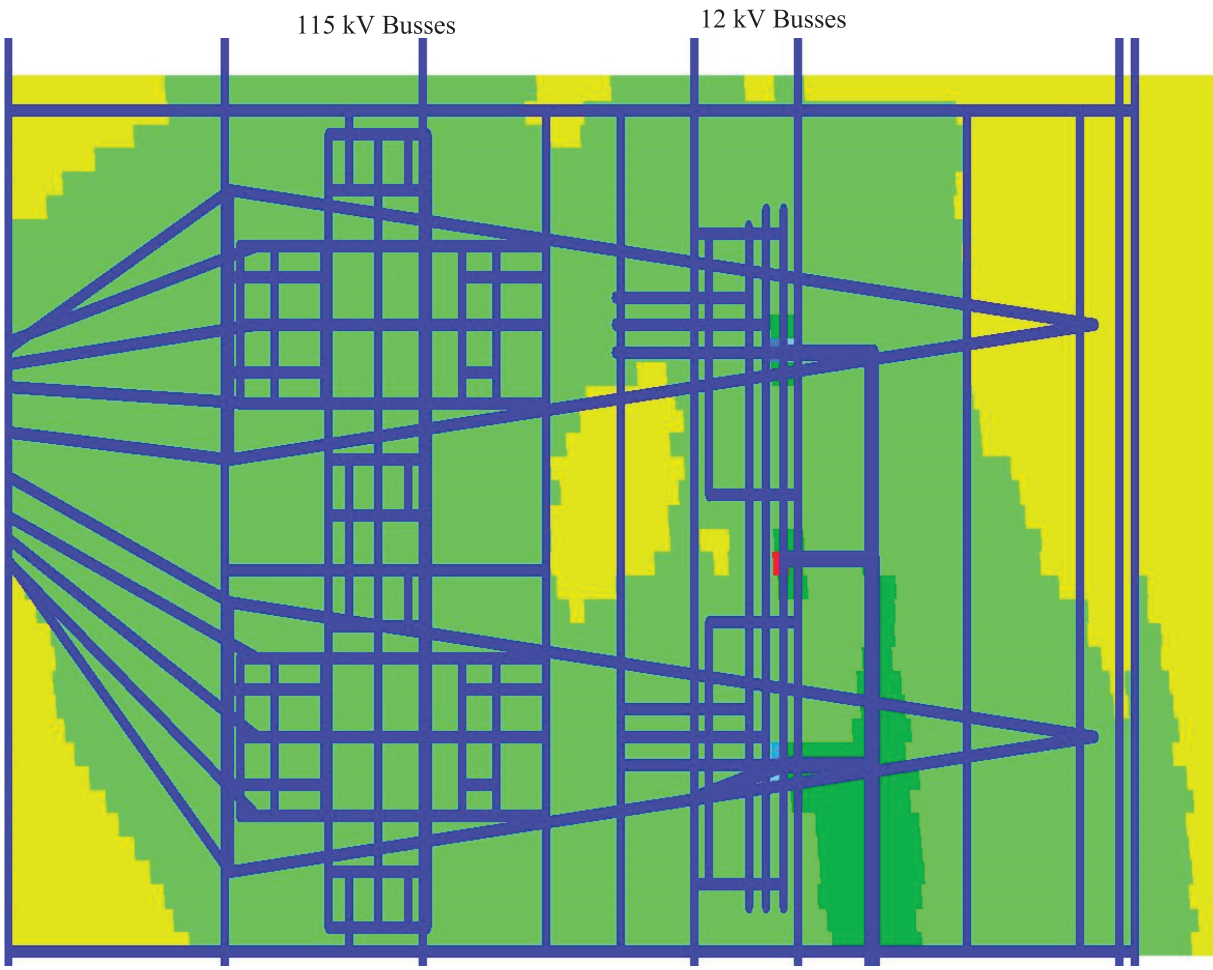


Figure 21: Calculated Magnetic Field Spot Contour Map for Expanded View of Lassen Substation for Future 115 kV System

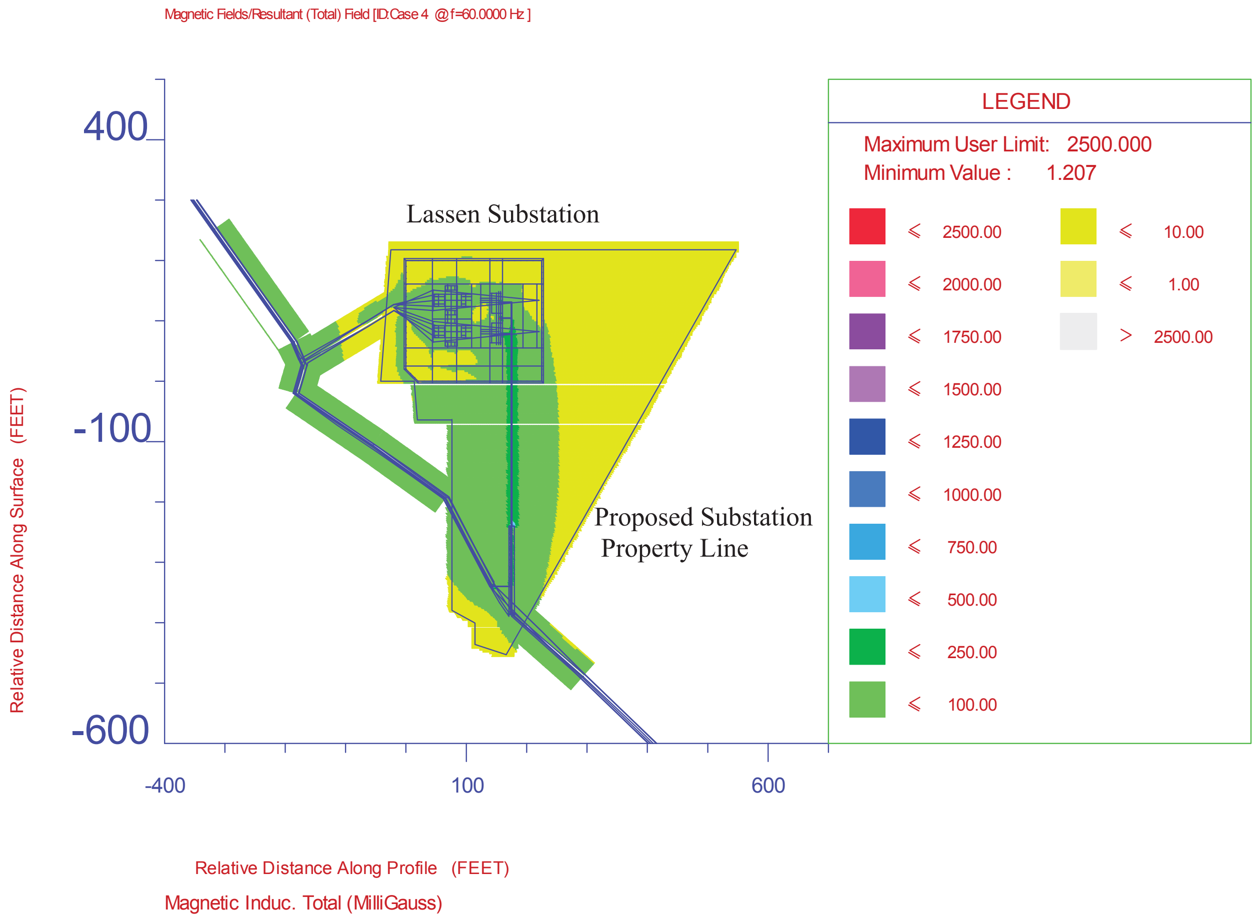


Figure 22: Calculated Magnetic Field Spot Contour Map for Lassen Substation Property and Transmission/Distribution Lines in Vicinity to the Substation for Future 115 kV System

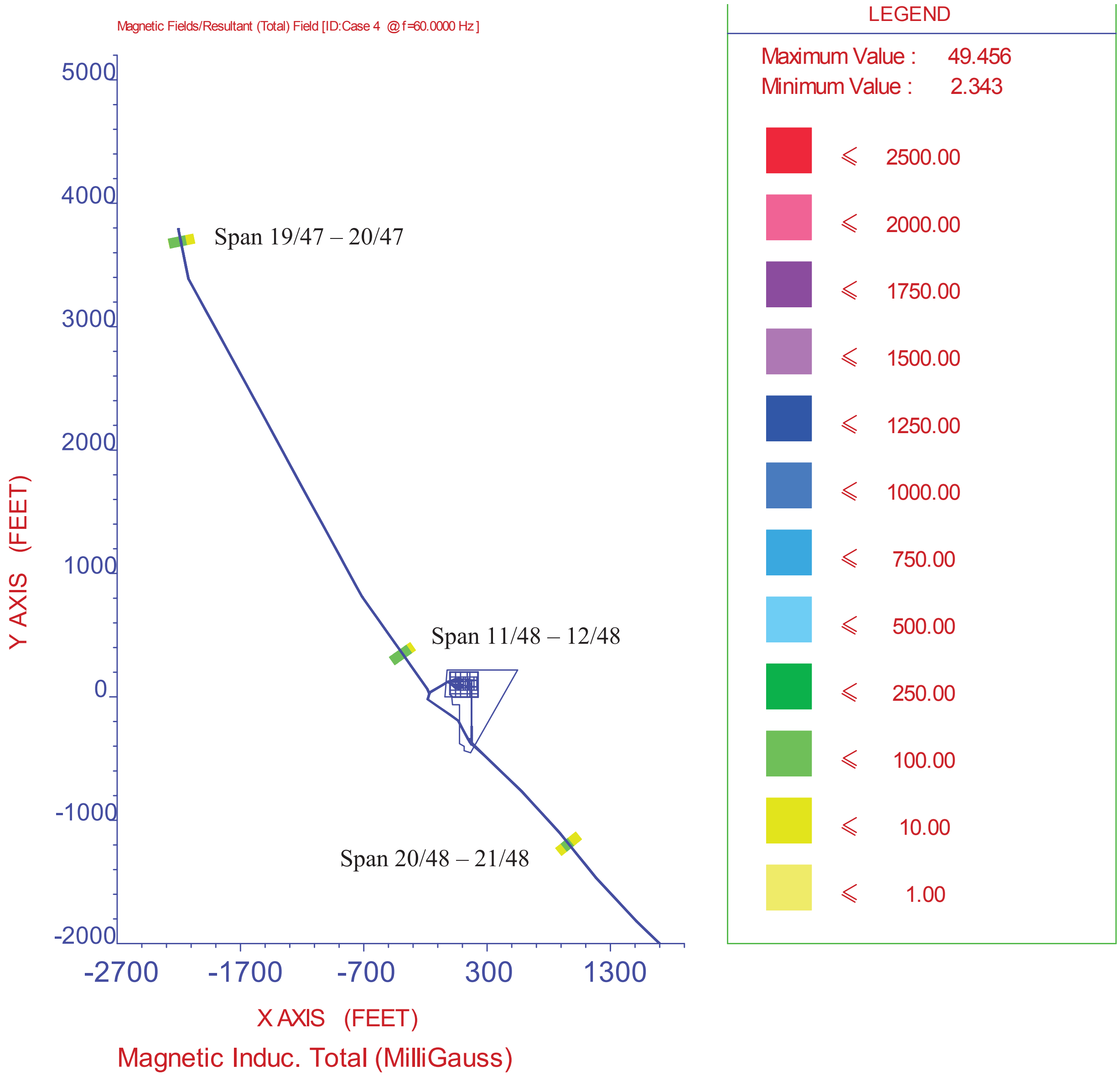


Figure 23: Calculated Magnetic Field Spot Contour Map for Profiles at Selected Locations of Transmission/Distribution Line Route for Future 115 kV System

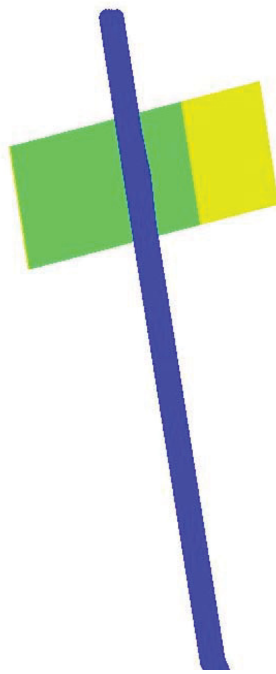


Figure 24: Calculated Magnetic Field Spot Contour Map for Profiles at Span 19/47 – 20/47 for Future 115 kV System

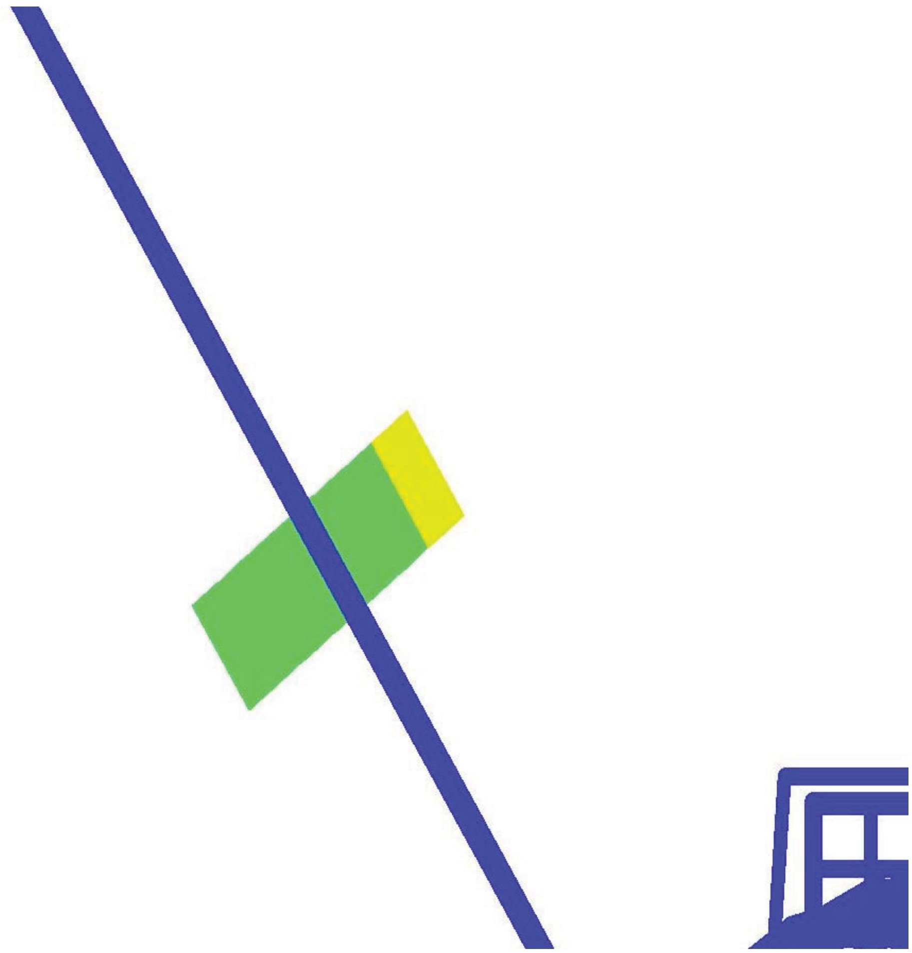


Figure 25: Calculated Magnetic Field Spot Contour Map for Profiles at Span 11/48 – 12/48 for Future 115 kV System

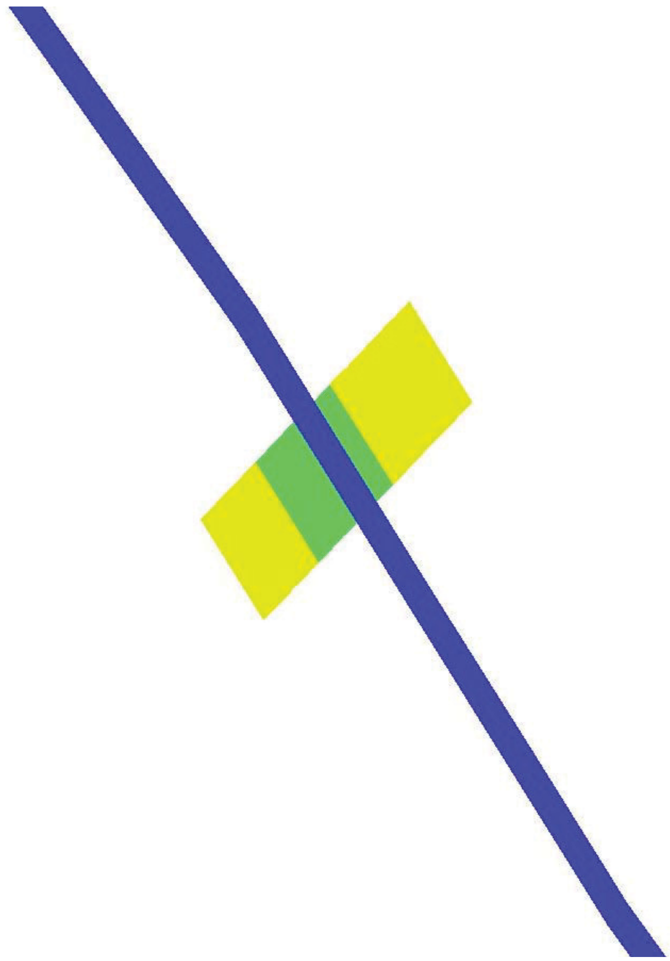


Figure 26: Calculated Magnetic Field Spot Contour Map for Profiles at Span 20/48 – 21/48 for Future 115 kV System

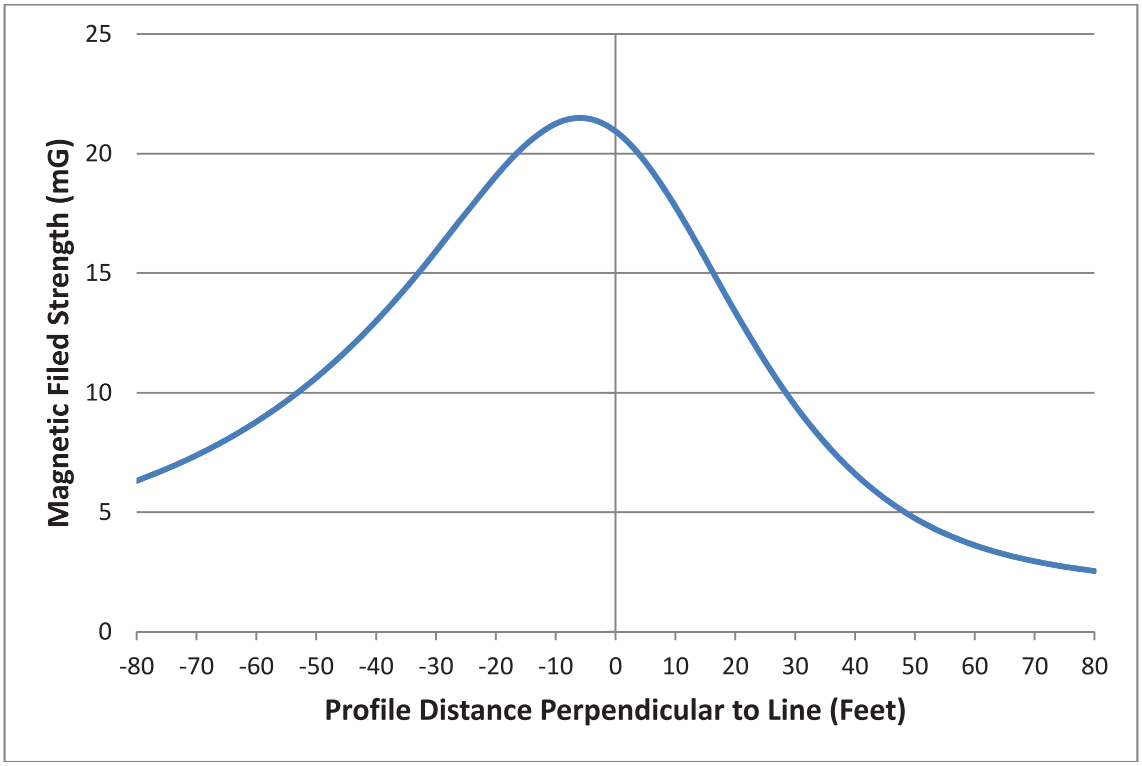


Figure 27: Calculated Magnetic Field Strength for Local 12.47 kV Distribution Lines

3219/016/X175590.v1

EXHIBIT D

PACIFICORP FINANCIAL STATEMENTS

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

[X] Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended June 30, 2015

or

[ ] Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from ______ to ______

Commission File Number	Exact name of registrant as specified in its charter; State or other jurisdiction of incorporation or organization	IRS Employer Identification No.
1-5152	**PACIFICORP** **(An Oregon Corporation)** **825 N.E. Multnomah Street** **Portland, Oregon 97232** **503-813-5645**	**93-0246090**

N/A

(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes ☐ No ☒

All of the shares of outstanding common stock are indirectly owned by Berkshire Hathaway Energy Company, 666 Grand Avenue, Des Moines, Iowa 50309-2580. As of July 31, 2015, 357,060,915 shares of common stock were outstanding.

TABLE OF CONTENTS

PART I

PART II

Definition of Abbreviations and Industry Terms

When used in Forward-Looking Statements, Part I - Items 2 through 4, and Part II - Items 1 through 6, the following terms have the definitions indicated.

PacifiCorp and Related Entities

BHE	Berkshire Hathaway Energy Company
PacifiCorp	PacifiCorp and its subsidiaries
PPW Holdings	PPW Holdings LLC, a wholly owned subsidiary of BHE and PacifiCorp's direct parent company
Lake Side 2	631-megawatt combined-cycle combustion turbine natural gas-fueled generating facility

Certain Industry Terms

AFUDC	Allowance for Funds Used During Construction
CPUC	California Public Utilities Commission
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GWh	Gigawatt Hours
IPUC	Idaho Public Utilities Commission
MWh	Megawatt Hours
OPUC	Oregon Public Utility Commission
REC	Renewable Energy Credit
UPSC	Utah Public Service Commission
WPSC	Wyoming Public Service Commission
WUTC	Washington Utilities and Transportation Commission

Forward-Looking Statements

This report contains statements that do not directly or exclusively relate to historical facts. These statements are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements can typically be identified by the use of forward-looking words, such as "will," "may," "could," "project," "believe," "anticipate," "expect," "estimate," "continue," "intend," "potential," "plan," "forecast" and similar terms. These statements are based upon PacifiCorp's current intentions, assumptions, expectations and beliefs and are subject to risks, uncertainties and other important factors. Many of these factors are outside the control of PacifiCorp and could cause actual results to differ materially from those expressed or implied by such forward-looking statements. These factors include, among others:

- general economic, political and business conditions, as well as changes in, and compliance with, laws and regulations, including reliability and safety standards, affecting PacifiCorp's operations or related industries;
- changes in, and compliance with, environmental laws, regulations, decisions and policies that could, among other items, increase operating and capital costs, reduce generating facility output, accelerate generating facility retirements or delay generating facility construction or acquisition;
- the outcome of rate cases and other proceedings conducted by regulatory commissions or other governmental and legal bodies and PacifiCorp's ability to recover costs in rates in a timely manner;
- changes in economic, industry or weather conditions, as well as demographic trends, new technologies and various conservation, energy efficiency and distributed generation measures and programs, that could affect customer growth and usage, electricity supply or PacifiCorp's ability to obtain long-term contracts with customers and suppliers;
- performance and availability of PacifiCorp's generating facilities, including the impacts of outages and repairs, transmission constraints, weather, including wind and hydroelectric conditions, and operating conditions;
- a high degree of variance between actual and forecasted load or generation that could impact PacifiCorp's hedging strategy and the cost of balancing its generation resources with its retail load obligations;
- changes in prices, availability and demand for wholesale electricity, coal, natural gas, other fuel sources and fuel transportation that could have a significant impact on generating capacity and energy costs;
- hydroelectric conditions and the cost, feasibility and eventual outcome of hydroelectric relicensing proceedings that could have a significant impact on generating capacity and cost and PacifiCorp's ability to generate electricity;
- the effects of catastrophic and other unforeseen events, which may be caused by factors beyond PacifiCorp's control or by a breakdown or failure of PacifiCorp's operating assets, including storms, floods, fires, earthquakes, explosions, landslides, mining accidents, litigation, wars, terrorism and embargoes;
- the financial condition and creditworthiness of PacifiCorp's significant customers and suppliers;
- changes in business strategy or development plans;
- availability, terms and deployment of capital, including reductions in demand for investment-grade commercial paper, debt securities and other sources of debt financing and volatility in the London Interbank Offered Rate, the base interest rate for PacifiCorp's credit facilities;
- changes in PacifiCorp's credit ratings;
- the impact of certain contracts used to mitigate or manage volume, price and interest rate risk, including increased collateral requirements, and changes in commodity prices, interest rates and other conditions that affect the fair value of certain contracts;
- the impact of inflation on costs and PacifiCorp's ability to recover such costs in rates;
- increases in employee healthcare costs, including the implementation of the Affordable Care Act;

- the impact of investment performance and changes in interest rates, legislation, healthcare cost trends, mortality and morbidity on pension and other postretirement benefits expense and funding requirements;

- unanticipated construction delays, changes in costs, receipt of required permits and authorizations, ability to fund capital projects and other factors that could affect future generating facilities and infrastructure additions;

- the impact of new accounting guidance or changes in current accounting estimates and assumptions on PacifiCorp's consolidated financial results; and

- other business or investment considerations that may be disclosed from time to time in PacifiCorp's filings with the United States Securities and Exchange Commission or in other publicly disseminated written documents.

Further details of the potential risks and uncertainties affecting PacifiCorp are described in its filings with the United States Securities and Exchange Commission, including Part II, Item 1A and other discussions contained in this Form 10-Q. PacifiCorp undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing factors should not be construed as exclusive.

PART I

Item 1. Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
PacifiCorp
Portland, Oregon

We have reviewed the accompanying consolidated balance sheet of PacifiCorp and subsidiaries ("PacifiCorp") as of June 30, 2015, and the related consolidated statements of operations for the three-month and six-month periods ended June 30, 2015 and 2014, and of changes in shareholders' equity and cash flows for the six-month periods ended June 30, 2015 and 2014. These interim financial statements are the responsibility of PacifiCorp's management.

We conducted our reviews in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our reviews, we are not aware of any material modifications that should be made to such consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of PacifiCorp and subsidiaries as of December 31, 2014, and the related consolidated statements of operations, comprehensive income, changes in shareholders' equity, and cash flows for the year then ended (not presented herein); and in our report dated February 27, 2015, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2014 is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Deloitte & Touche LLP

Portland, Oregon
August 7, 2015

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (Unaudited)
(Amounts in millions)

	As of	
	June 30, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 96	$ 23
Accounts receivable, net	727	701
Income taxes receivable	—	133
Inventories:		
Materials and supplies	231	218
Fuel	191	199
Deferred income taxes	27	28
Regulatory assets	118	131
Other current assets	76	92
Total current assets	1,466	1,525
Property, plant and equipment, net	18,900	18,719
Regulatory assets	1,558	1,574
Other assets	414	449
Total assets	$ 22,338	$ 22,267

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (Unaudited) (continued)
(Amounts in millions)

	As of	
	June 30, 2015	December 31, 2014
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 457	$ 465
Income taxes payable	83	—
Accrued employee expenses	114	76
Accrued interest	111	110
Accrued property and other taxes	95	59
Short-term debt	—	20
Current portion of long-term debt and capital lease obligations	179	134
Regulatory liabilities	32	34
Other current liabilities	221	222
Total current liabilities	1,292	1,120
Regulatory liabilities	930	910
Long-term debt and capital lease obligations	7,123	6,919
Deferred income taxes	4,615	4,609
Other long-term liabilities	1,017	953
Total liabilities	14,977	14,511
Commitments and contingencies (Note 10)		
Shareholders' equity:		
Preferred stock	2	2
Common stock - 750 shares authorized, no par value, 357 shares issued and outstanding	—	—
Additional paid-in capital	4,479	4,479
Retained earnings	2,893	3,288
Accumulated other comprehensive loss, net	(13)	(13)
Total shareholders' equity	7,361	7,756
Total liabilities and shareholders' equity	$ 22,338	$ 22,267

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS (Unaudited)
(Amounts in millions)

	Three-Month Periods Ended June 30,		Six-Month Periods Ended June 30,	
	2015	2014	2015	2014
Operating revenue	$ 1,269	$ 1,243	$ 2,519	$ 2,531
Operating costs and expenses:				
Energy costs	437	444	913	948
Operations and maintenance	272	241	540	514
Depreciation and amortization	190	177	379	356
Taxes, other than income taxes	45	40	90	82
Total operating costs and expenses	944	902	1,922	1,900
Operating income	325	341	597	631
Other income (expense):				
Interest expense	(94)	(97)	(188)	(191)
Allowance for borrowed funds	4	7	10	15
Allowance for equity funds	9	14	19	30
Other, net	2	3	5	5
Total other income (expense)	(79)	(73)	(154)	(141)
Income before income tax expense	246	268	443	490
Income tax expense	75	84	138	151
Net income	$ 171	$ 184	$ 305	$ 339

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY (Unaudited)
(Amounts in millions)

	Preferred Stock	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Total Shareholders' Equity
Balance, December 31, 2013	$ 2	$ —	$ 4,479	$ 3,315	$ (9)	$ 7,787
Net income	—	—	—	339	—	339
Common stock dividends declared	—	—	—	(625)	—	(625)
Balance, June 30, 2014	$ 2	$ —	$ 4,479	$ 3,029	$ (9)	$ 7,501
Balance, December 31, 2014	$ 2	$ —	$ 4,479	$ 3,288	$ (13)	$ 7,756
Net income	—	—	—	305	—	305
Common stock dividends declared	—	—	—	(700)	—	(700)
Balance, June 30, 2015	$ 2	$ —	$ 4,479	$ 2,893	$ (13)	$ 7,361

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)
(Amounts in millions)

	Six-Month Periods Ended June 30, 2015	2014
Cash flows from operating activities:		
Net income	$ 305	$ 339
Adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization	379	356
Allowance for equity funds	(19)	(30)
Deferred income taxes and amortization of investment tax credits	9	105
Changes in regulatory assets and liabilities	18	(43)
Other, net	3	11
Changes in other operating assets and liabilities:		
Accounts receivable and other assets	19	45
Derivative collateral, net	(30)	12
Inventories	(5)	18
Income taxes	216	18
Accounts payable and other liabilities	92	55
Net cash flows from operating activities	987	886
Cash flows from investing activities:		
Capital expenditures	(419)	(532)
Other, net	(22)	(3)
Net cash flows from investing activities	(441)	(535)
Cash flows from financing activities:		
Proceeds from long-term debt	250	425
Repayments of long-term debt and capital lease obligations	(1)	(13)
Net repayments of short-term debt	(20)	—
Common stock dividends	(700)	(625)
Other, net	(2)	(3)
Net cash flows from financing activities	(473)	(216)
Net change in cash and cash equivalents	73	135
Cash and cash equivalents at beginning of period	23	53
Cash and cash equivalents at end of period	$ 96	$ 188

The accompanying notes are an integral part of these consolidated financial statements.

(1) General

PacifiCorp, which includes PacifiCorp and its subsidiaries, is a United States regulated electric utility company serving retail customers, including residential, commercial, industrial, irrigation and other customers in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp owns, or has interests in, a number of thermal, hydroelectric, wind-powered and geothermal generating facilities, as well as electric transmission and distribution assets. PacifiCorp also buys and sells electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants. PacifiCorp is subject to comprehensive state and federal regulation. PacifiCorp's subsidiaries support its electric utility operations by providing coal mining services. PacifiCorp is an indirect subsidiary of Berkshire Hathaway Energy Company ("BHE"), a holding company based in Des Moines, Iowa that owns subsidiaries principally engaged in energy businesses. BHE is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

The unaudited Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") for interim financial information and the United States Securities and Exchange Commission's rules and regulations for Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the disclosures required by GAAP for annual financial statements. Management believes the unaudited Consolidated Financial Statements contain all adjustments (consisting only of normal recurring adjustments) considered necessary for the fair presentation of the unaudited Consolidated Financial Statements as of June 30, 2015 and for the three- and six-month periods ended June 30, 2015 and 2014. The results of operations for the three- and six-month periods ended June 30, 2015 are not necessarily indicative of the results to be expected for the full year.

The preparation of the unaudited Consolidated Financial Statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the unaudited Consolidated Financial Statements and the reported amounts of revenue and expenses during the period. Actual results may differ from the estimates used in preparing the unaudited Consolidated Financial Statements. Note 2 of Notes to Consolidated Financial Statements included in PacifiCorp's Annual Report on Form 10-K for the year ended December 31, 2014 describes the most significant accounting policies used in the preparation of the unaudited Consolidated Financial Statements. There have been no significant changes in PacifiCorp's assumptions regarding significant accounting estimates and policies during the six-month period ended June 30, 2015.

(2) New Accounting Pronouncements

In April 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2015-03, which amends FASB Accounting Standards Codification ("ASC") Subtopic 835-30, "Interest - Imputation of Interest." The amendments in this guidance require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability instead of as an asset. This guidance is effective for interim and annual reporting periods beginning after December 15, 2015, with early adoption permitted. This guidance must be adopted retrospectively, wherein the balance sheet of each period presented should be adjusted to reflect the new guidance. PacifiCorp is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In May 2014, the FASB issued ASU No. 2014-09, which creates FASB ASC Topic 606, "Revenue from Contracts with Customers" and supersedes ASC Topic 605, "Revenue Recognition." The guidance replaces industry-specific guidance and establishes a single five-step model to identify and recognize revenue. The core principle of the guidance is that an entity should recognize revenue upon transfer of control of promised goods or services to customers in an amount that reflects the consideration to which an entity expects to be entitled in exchange for those goods or services. Additionally, the guidance requires the entity to disclose further quantitative and qualitative information regarding the nature and amount of revenues arising from contracts with customers, as well as other information about the significant judgments and estimates used in recognizing revenues from contracts with customers. In July 2015, the FASB decided to defer the effective date one year to interim and annual reporting periods beginning after December 15, 2017. This guidance may be adopted retrospectively or under a modified retrospective method where the cumulative effect is recognized at the date of initial application. PacifiCorp is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following (in millions):

		As of	
	Depreciable Life	June 30, 2015	December 31, 2014
Property, plant and equipment in-service	5-75 years	$ 26,503	$ 25,813
Accumulated depreciation and amortization		(8,247)	(8,026)
Net property, plant and equipment in-service		18,256	17,787
Construction work-in-progress		644	932
Total property, plant and equipment, net		$ 18,900	$ 18,719

(4) Regulatory Matters

Utah Mine Disposition

Due to quality issues with the coal reserves at PacifiCorp's Deer Creek mine in Utah and rising costs at PacifiCorp's wholly owned subsidiary, Energy West Mining Company, PacifiCorp believes the Deer Creek coal reserves are no longer able to be economically mined. As a result, in December 2014, PacifiCorp filed applications with the Utah Public Service Commission ("UPSC"), the Oregon Public Utility Commission ("OPUC"), the Wyoming Public Service Commission ("WPSC") and the Idaho Public Utilities Commission ("IPUC") seeking certain approvals, prudence determinations and accounting orders to close its Deer Creek mining operations, sell certain Utah mining assets, enter into a replacement coal supply agreement, amend an existing coal supply agreement, withdraw from the United Mine Workers of America ("UMWA") 1974 Pension Plan and settle PacifiCorp's other postretirement benefit obligation for UMWA participants (collectively, the "Utah Mine Disposition"). PacifiCorp also filed an advice letter with the California Public Utilities Commission. In April 2015, PacifiCorp filed all-party settlement stipulations with the UPSC and the WPSC finding that the decision to enter into the Utah Mine Disposition transaction is prudent and in the public interest. The UPSC approved the stipulation in April 2015 and the WPSC approved the stipulation in May 2015. In May 2015, the OPUC issued its final order concluding that the Utah Mine Disposition transaction produces net benefits for customers and is in the public interest. The IPUC also issued an order in May 2015, approving the Utah Mine Disposition and ruling that the decision to enter into the transaction is prudent and in the public interest. Accordingly, in June 2015, PacifiCorp sold the specified Utah mining assets and the replacement and amended coal supply agreements became effective. Refer to Note 10 for discussion of the contractual obligations related to the replacement coal supply agreement. Refer to Note 6 for discussion of the UMWA 1974 Pension Plan withdrawal and the settlement of the other postretirement benefit obligation for UMWA participants. The Deer Creek mine is currently idled and closure activities have begun.

(5) Recent Financing Transactions

In June 2015, PacifiCorp issued $250 million of its 3.35% First Mortgage Bonds due July 2025. The net proceeds were used to fund capital expenditures and for general corporate purposes, including retirement of short-term debt.

In March 2015, PacifiCorp obtained $191 million of letters of credit to support variable-rate tax-exempt bond obligations. These letters of credit expire through March 2017 and replace certain letters of credit previously issued under one of the credit facilities. Also, in March 2015, PacifiCorp arranged for the cancellation of $23 million of letters of credit previously issued under one of the credit facilities to support variable-rate tax-exempt bond obligations.

As of June 30, 2015, PacifiCorp had $428 million of fully available letters of credit issued under committed arrangements to support variable-rate tax-exempt bond obligations, of which $56 million were issued under credit facilities.

(6) Employee Benefit Plans

Net periodic benefit cost for the pension and other postretirement benefit plans included the following components (in millions):

	Three-Month Periods Ended June 30,		Six-Month Periods Ended June 30,	
	2015	2014	2015	2014
Pension:				
Service cost	$ 1	$ 1	$ 2	$ 2
Interest cost	14	14	27	28
Expected return on plan assets	(20)	(19)	(39)	(38)
Net amortization	11	7	21	15
Net periodic benefit cost	$ 6	$ 3	$ 11	$ 7
Other postretirement:				
Service cost	$ 1	$ 2	$ 2	$ 3
Interest cost	4	7	8	14
Expected return on plan assets	(6)	(7)	(12)	(15)
Net amortization	(1)	—	(2)	1
Net periodic benefit cost	$ (2)	$ 2	$ (4)	$ 3

Employer contributions to the pension and other postretirement benefit plans are expected to be $4 million and $- million, respectively, during 2015. As of June 30, 2015, $2 million and $- million of contributions had been made to the pension and other postretirement benefit plans, respectively.

Utah Mine Disposition and Labor Agreement

In conjunction with the Utah Mine Disposition described in Note 4, in December 2014, Energy West Mining Company reached a labor settlement with the UMWA covering union employees at PacifiCorp's Deer Creek mining operations. As a result of the labor settlement, the UMWA agreed to assume PacifiCorp's other postretirement benefit obligation associated with UMWA plan participants in exchange for PacifiCorp transferring $150 million to a fund managed by the UMWA. Transfer of the assets and settlement of this obligation occurred in May 2015 and resulted in a remeasurement of the other postretirement plan assets and benefit obligation. As a result of the remeasurement, PacifiCorp recognized a $9 million settlement loss, with the portion that is probable of recovery deferred as a regulatory asset.

Multiemployer Pension Plan

PacifiCorp's subsidiary, Energy West Mining Company, triggered involuntary withdrawal from the UMWA 1974 Pension Plan in June 2015 when the UMWA employees ceased performing work for PacifiCorp. PacifiCorp recorded its best estimate of the withdrawal obligation in December 2014 when withdrawal was considered probable and deferred the portion of the obligation considered probable of recovery to a regulatory asset.

(7) Asset Retirement Obligations

In December 2014, the United States Environmental Protection Agency released its final rule regulating the management and disposal of coal combustion byproducts resulting from the operation of coal-fueled generating facilities, including requirements for the operation and closure of surface impoundment and ash landfill facilities. The final rule was published in the Federal Register in April 2015 and will be effective in October 2015. As of June 30, 2015 and December 31, 2014, PacifiCorp's asset retirement obligations totaled $227 million and $135 million, respectively, and the change was substantially due to the impacts of the final rule.

(8) Risk Management and Hedging Activities

PacifiCorp is exposed to the impact of market fluctuations in commodity prices and interest rates. PacifiCorp is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk as it has an obligation to serve retail customer load in its service territories. PacifiCorp's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. Interest rate risk exists on variable-rate debt and future debt issuances. PacifiCorp does not engage in a material amount of proprietary trading activities.

PacifiCorp has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its business. To mitigate a portion of its commodity price risk, PacifiCorp uses commodity derivative contracts, which may include forwards, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. PacifiCorp manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. Additionally, PacifiCorp may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate PacifiCorp's exposure to interest rate risk. No interest rate derivatives were in place during the periods presented. PacifiCorp does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in PacifiCorp's accounting policies related to derivatives. Refer to Note 9 for additional information on derivative contracts.

The following table, which reflects master netting arrangements and excludes contracts that have been designated as normal under the normal purchases or normal sales exception afforded by GAAP, summarizes the fair value of PacifiCorp's derivative contracts, on a gross basis, and reconciles those amounts to the amounts presented on a net basis on the Consolidated Balance Sheets (in millions):

	Other Current Assets	Other Assets	Other Current Liabilities	Other Long-term Liabilities	Total
As of June 30, 2015					
Not designated as hedging contracts[1]:					
Commodity assets	$ 17	$ —	$ 1	$ —	$ 18
Commodity liabilities	(3)	—	(41)	(77)	(121)
Total	14	—	(40)	(77)	(103)
Total derivatives	14	—	(40)	(77)	(103)
Cash collateral receivable	—	—	14	44	58
Total derivatives - net basis	$ 14	$ —	$ (26)	$ (33)	$ (45)
As of December 31, 2014					
Not designated as hedging contracts[1]:					
Commodity assets	$ 28	$ —	$ 1	$ —	$ 29
Commodity liabilities	(10)	—	(55)	(49)	(114)
Total	18	—	(54)	(49)	(85)
Total derivatives	18	—	(54)	(49)	(85)
Cash collateral receivable	—	—	14	14	28
Total derivatives - net basis	$ 18	$ —	$ (40)	$ (35)	$ (57)

(1) PacifiCorp's commodity derivatives are generally included in rates and as of June 30, 2015 and December 31, 2014, a regulatory asset of $99 million and $85 million, respectively, was recorded related to the net derivative liability of $103 million and $85 million, respectively.

The following table reconciles the beginning and ending balances of PacifiCorp's regulatory assets and summarizes the pre-tax gains and losses on commodity derivative contracts recognized in regulatory assets, as well as amounts reclassified to earnings (in millions):

	Three-Month Periods Ended June 30,		Six-Month Periods Ended June 30,	
	2015	2014	2015	2014
Beginning balance	$ 130	$ 27	$ 85	$ 55
Changes in fair value recognized in regulatory assets	(21)	(27)	27	(49)
Net gains (losses) reclassified to operating revenue	3	—	28	(11)
Net (losses) gains reclassified to energy costs	(13)	—	(41)	5
Ending balance	$ 99	$ —	$ 99	$ —

Derivative Contract Volumes

The following table summarizes the net notional amounts of outstanding commodity derivative contracts with fixed price terms that comprise the mark-to-market values as of (in millions):

	Unit of Measure	June 30, 2015	December 31, 2014
Electricity purchases (sales)	Megawatt hours	1	(1)
Natural gas purchases	Decatherms	110	113
Fuel oil purchases	Gallons	7	3

Credit Risk

PacifiCorp is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent PacifiCorp's counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, PacifiCorp analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, PacifiCorp enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. If required, PacifiCorp exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

Collateral and Contingent Features

In accordance with industry practice, certain wholesale derivative contracts contain credit support provisions that in part base certain collateral requirements on credit ratings for senior unsecured debt as reported by one or more of the three recognized credit rating agencies. These derivative contracts may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance" in the event of a material adverse change in PacifiCorp's creditworthiness. These rights can vary by contract and by counterparty. As of June 30, 2015, PacifiCorp's credit ratings from the three recognized credit rating agencies were investment grade.

The aggregate fair value of PacifiCorp's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $116 million and $113 million as of June 30, 2015 and December 31, 2014, respectively, for which PacifiCorp had posted collateral of $58 million and $28 million, respectively, in the form of cash deposits. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of June 30, 2015 and December 31, 2014, PacifiCorp would have been required to post $54 million and $75 million, respectively, of additional collateral. PacifiCorp's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors.

(9) Fair Value Measurements

The carrying value of PacifiCorp's cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. PacifiCorp has various financial assets and liabilities that are measured at fair value on the Consolidated Financial Statements using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 - Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that PacifiCorp has the ability to access at the measurement date.
- Level 2 - Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).
- Level 3 - Unobservable inputs reflect PacifiCorp's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. PacifiCorp develops these inputs based on the best information available, including its own data.

The following table presents PacifiCorp's assets and liabilities recognized on the Consolidated Balance Sheets and measured at fair value on a recurring basis (in millions):

	Input Levels for Fair Value Measurements				
	Level 1	Level 2	Level 3	Other(1)	Total
As of June 30, 2015					
Assets:					
Commodity derivatives	$ —	$ 16	$ 2	$ (4)	$ 14
Money market mutual funds(2)	91	—	—	—	91
Investment funds	16	—	—	—	16
	$ 107	$ 16	$ 2	$ (4)	$ 121
Liabilities - Commodity derivatives	$ —	$ (121)	$ —	$ 62	$ (59)
As of December 31, 2014					
Assets:					
Commodity derivatives	$ —	$ 25	$ 4	$ (11)	$ 18
Money market mutual funds(2)	30	—	—	—	30
	$ 30	$ 25	$ 4	$ (11)	$ 48
Liabilities - Commodity derivatives	$ —	$ (114)	$ —	$ 39	$ (75)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $58 million and $28 million as of June 30, 2015 and December 31, 2014, respectively.

(2) Amounts are included in cash and cash equivalents, other current assets and other assets on the Consolidated Balance Sheets. Money market mutual funds are accounted for as available-for-sale securities and the fair value approximates cost.

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which PacifiCorp transacts. When quoted prices for identical contracts are not available, PacifiCorp uses forward price curves. Forward price curves represent PacifiCorp's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. PacifiCorp bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent energy brokers, exchanges, direct communication with market participants and actual transactions executed by PacifiCorp. Market price quotations for certain major electricity and natural gas trading hubs are generally readily obtainable for the first six years; therefore, PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. Market price quotations for other electricity and natural gas trading hubs are not as readily obtainable for the first six years. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, PacifiCorp uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts. Refer to Note 8 for further discussion regarding PacifiCorp's risk management and hedging activities.

PacifiCorp's investments in money market mutual funds and investment funds are stated at fair value. PacifiCorp uses a readily observable quoted market price or net asset value of an identical security in an active market to record the fair value.

PacifiCorp's long-term debt is carried at cost on the Consolidated Financial Statements. The fair value of PacifiCorp's long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of PacifiCorp's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying value and estimated fair value of PacifiCorp's long-term debt (in millions):

	As of June 30, 2015		As of December 31, 2014	
	Carrying Value	**Fair Value**	**Carrying Value**	**Fair Value**
Long-term debt	$ 7,269	$ 8,382	$ 7,019	$ 8,358

(10) Commitments and Contingencies

Legal Matters

PacifiCorp is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. PacifiCorp does not believe that such normal and routine litigation will have a material impact on its consolidated financial results. PacifiCorp is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines, penalties and other costs in substantial amounts and are described below.

USA Power

In October 2005, prior to BHE's ownership of PacifiCorp, PacifiCorp was added as a defendant to a lawsuit originally filed in February 2005 in the Third District Court of Salt Lake County, Utah ("Third District Court") by USA Power, LLC, USA Power Partners, LLC and Spring Canyon Energy, LLC (collectively, the "Plaintiff"). The Plaintiff's complaint alleged that PacifiCorp misappropriated confidential proprietary information in violation of Utah's Uniform Trade Secrets Act and accused PacifiCorp of breach of contract and related claims in regard to the Plaintiff's 2002 and 2003 proposals to build a natural gas-fueled generating facility in Juab County, Utah. In October 2007, the Third District Court granted PacifiCorp's motion for summary judgment on all counts and dismissed the Plaintiff's claims in their entirety. In a May 2010 ruling on the Plaintiff's petition for reconsideration, the Utah Supreme Court reversed summary judgment and remanded the case back to the Third District Court for further consideration. In May 2012, a jury awarded damages to the Plaintiff for breach of contract and misappropriation of a trade secret in the amounts of $18 million for actual damages and $113 million for unjust enrichment. In May 2012, the Plaintiff filed a motion seeking exemplary damages. Under the Utah Uniform Trade Secrets law, the judge may award exemplary damages in an additional amount not to exceed twice the original award. The Plaintiff also filed a motion to seek recovery of attorneys' fees in an amount equal to 40% of all amounts ultimately awarded in the case. In October 2012, PacifiCorp filed post-trial motions for a judgment notwithstanding the verdict and a new trial. As a result of a hearing in December 2012, the trial judge denied PacifiCorp's post-trial motions with the exception of reducing the aggregate amount of damages to $113 million. In January 2013, the Plaintiff filed a motion for prejudgment interest. An initial judgment was entered in April 2013 in which the trial judge denied the Plaintiff's motions for exemplary damages and prejudgment interest and ruled that PacifiCorp must pay the Plaintiff's attorneys' fees based on applying a reasonable rate to hours worked. In May 2013, a final judgment was entered against PacifiCorp in the amount of $115 million, which includes the $113 million of aggregate damages previously awarded and amounts awarded for the Plaintiff's attorneys' fees. The final judgment also ordered that postjudgment interest accrue beginning as of the date of the April 2013 initial judgment. In May 2013, PacifiCorp posted a surety bond issued by a subsidiary of Berkshire Hathaway to secure its estimated obligation. PacifiCorp strongly disagrees with the jury's verdict and is vigorously pursuing all appellate measures. Both PacifiCorp and the Plaintiff filed appeals with the Utah Supreme Court. Briefing before the Utah Supreme Court is complete and oral arguments are scheduled for September 2015. As of June 30, 2015, PacifiCorp had accrued $120 million for the final judgment and postjudgment interest, and believes the likelihood of any additional material loss is remote; however, any additional awards against PacifiCorp could also have a material effect on the consolidated financial results. Any payment of damages will be at the end of the appeals process, which could take as long as several years.

Sanpete County, Utah Rangeland Fire

In June 2012, a major rangeland fire occurred in Sanpete County, Utah. Certain parties allege that contact between two of PacifiCorp's transmission lines may have triggered a ground fault that led to the fire. PacifiCorp has engaged experts to review the cause and origin of the fire, as well as to assess the damages. PacifiCorp has accrued its best estimate of the potential loss and expected insurance recovery. PacifiCorp believes it is reasonably possible it may incur additional loss beyond the amount accrued, but does not believe the potential additional loss will have a material impact on its consolidated financial results.

Environmental Laws and Regulations

PacifiCorp is subject to federal, state and local laws and regulations regarding air and water quality, renewable portfolio standards, emissions performance standards, climate change, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact PacifiCorp's current and future operations. PacifiCorp believes it is in material compliance with all applicable laws and regulations.

Commitments

As a result of the Utah Mine Disposition discussed in Note 4, PacifiCorp's replacement coal supply agreement for one of its generating facilities became effective in June 2015. Also during the three-month period ended June 30, 2015, PacifiCorp entered into several purchased electricity contracts from facilities that have not yet achieved commercial operation. These coal supply and purchased electricity contracts result in minimum future purchases of $70 million in 2016, $112 million in 2017, $127 million in 2018, $127 million in 2019 and $1.601 billion in 2020 and thereafter.

(11) Related Party Transactions

Berkshire Hathaway includes BHE and its subsidiaries in its United States federal income tax return. Consistent with established regulatory practice, PacifiCorp's provision for income taxes has been computed on a stand-alone basis, and substantially all of its currently payable or receivable income taxes are remitted to or received from BHE. For the six-month period ended June 30, 2015, PacifiCorp received net cash payments for federal and state income taxes from BHE totaling $87 million. For the six-month period ended June 30, 2014, PacifiCorp made net cash payments for federal and state income taxes to BHE totaling $27 million.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of PacifiCorp during the periods included herein. Explanations include management's best estimate of the impact of weather, customer growth and other factors. This discussion should be read in conjunction with PacifiCorp's historical unaudited Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 1 of this Form 10-Q. PacifiCorp's actual results in the future could differ significantly from the historical results.

Results of Operations for the Second Quarter and First Six Months of 2015 and 2014

Overview

Net income for the second quarter of 2015 was $171 million, a decrease of $13 million, or 7%, compared to 2014. Net income decreased due to the prior year recognition of expected insurance recoveries for fire claims, higher depreciation and amortization of $13 million and lower AFUDC of $8 million, partially offset by higher margins of $33 million. Margins increased primarily due to higher retail rates and higher retail customer load, partially offset by lower REC revenue and lower wholesale electricity revenue. Retail customer load increased 1.6% due to the impacts of hot weather in June 2015 on residential and commercial customers and an increase in the average number of residential and commercial customers primarily in Utah, partially offset by lower residential customer usage in Utah and lower irrigation customer usage primarily in Idaho. Energy generated remained relatively flat for the second quarter of 2015 compared to 2014 due to higher coal-fueled generation offset by lower hydroelectric, wind-powered and natural gas-fueled generation. Wholesale sales volumes decreased 17% and purchased electricity volumes decreased 8%.

Net income for the first six months of 2015 was $305 million, a decrease of $34 million, or 10%, compared to 2014. Net income decreased primarily due to the prior year recognition of expected insurance recoveries for fire claims, higher depreciation and amortization of $23 million and lower AFUDC of $16 million, partially offset by higher margins of $23 million. Margins increased primarily due to higher retail rates and lower natural gas generation, partially offset by lower wholesale electricity revenue volumes, higher coal costs and volumes, lower REC revenue and lower retail customer load. Retail customer load decreased 1.0% due to lower residential, irrigation and commercial customer usage, partially offset by an increase in the average number of residential customers in Utah and Oregon and an increase in the average number of commercial customers in Utah. The impacts of the hot weather in June 2015 on residential and commercial customers were largely offset by the impacts of mild weather in the first quarter of 2015 on residential and commercial customers primarily in Oregon and Washington. Energy generated decreased 5% for the first six months of 2015 compared to 2014 due to lower economical dispatch of natural gas-fueled generation and reduced hydroelectric and wind-powered generation, partially offset by the addition of Lake Side 2 and higher coal-fueled generation. Wholesale sales volumes decreased 13% and purchased electricity volumes increased 10%.

Operating revenue and energy costs are the key drivers of PacifiCorp's results of operations as they encompass retail and wholesale electricity revenue and the direct costs associated with providing electricity to customers. PacifiCorp believes that a discussion of gross margin, representing operating revenue less energy costs, is therefore meaningful.

A comparison of PacifiCorp's key operating results is as follows:

	Second Quarter				First Six Months			
	2015	2014	Change		2015	2014	Change	
Gross margin (in millions):								
Operating revenue	$ 1,269	$ 1,243	$ 26	2 %	$ 2,519	$ 2,531	$ (12)	— %
Energy costs	437	444	(7)	(2)	913	948	(35)	(4)
Gross margin	$ 832	$ 799	$ 33	4	$ 1,606	$ 1,583	$ 23	1
Sales (GWh):								
Residential	3,394	3,298	96	3 %	7,387	7,571	(184)	(2)%
Commercial	4,253	4,065	188	5	8,283	8,247	36	—
Industrial and irrigation	5,634	5,711	(77)	(1)	10,671	10,781	(110)	(1)
Other	105	107	(2)	(2)	209	209	—	—
Total retail	13,386	13,181	205	2	26,550	26,808	(258)	(1)
Wholesale	1,614	1,944	(330)	(17)	4,268	4,902	(634)	(13)
Total sales	15,000	15,125	(125)	(1)	30,818	31,710	(892)	(3)
Average number of retail customers (in thousands)	1,810	1,779	31	2 %	1,805	1,779	26	1 %
Average revenue per MWh:								
Retail	$ 88.32	$ 84.49	$ 3.83	5 %	$ 86.91	$ 84.25	$ 2.66	3 %
Wholesale	$ 28.65	$ 32.49	$ (3.84)	(12)%	$ 31.86	$ 33.59	$ (1.73)	(5)%
Sources of energy (GWh)(1):								
Coal	10,324	9,477	847	9 %	20,676	20,061	615	3 %
Natural gas	2,180	2,367	(187)	(8)	3,854	4,901	(1,047)	(21)
Hydroelectric(2)	657	1,035	(378)	(37)	1,681	2,249	(568)	(25)
Wind and other(2)	583	813	(230)	(28)	1,383	1,873	(490)	(26)
Total energy generated	13,744	13,692	52	—	27,594	29,084	(1,490)	(5)
Energy purchased	2,332	2,528	(196)	(8)	5,453	4,940	513	10
Total	16,076	16,220	(144)	(1)	33,047	34,024	(977)	(3)
Average cost of energy per MWh:								
Energy generated(3)	$ 19.55	$ 19.37	$ 0.18	1 %	$ 19.63	$ 19.99	$ (0.36)	(2)%
Energy purchased	$ 55.94	$ 53.08	$ 2.86	5 %	$ 51.04	$ 59.03	$ (7.99)	(14)%

(1) GWh amounts are net of energy used by the related generating facilities.

(2) All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of RECs or other environmental commodities.

(3) The average cost per MWh of energy generated includes only the cost of fuel associated with the generating facilities.

Gross margin increased $33 million, or 4%, for the second quarter of 2015 compared to 2014 primarily due to:

- $50 million of increases mainly from higher retail rates;
- $22 million of lower natural gas costs due to decreased generation and lower average unit costs; and
- $19 million of higher retail revenues from a 1.6% increase in retail customer load, with a 2.4% increase due to the impacts of hot weather in June 2015 on residential and commercial customers and a 0.8% increase in the average number of residential and commercial customers primarily in Utah, partially offset by 1.6% lower customer usage primarily by residential customers in Utah and irrigation customers primarily in Idaho.

The increase in gross margin was partially offset by:

- $25 million of higher coal costs due to increased volumes and higher average unit costs;
- $23 million of lower REC revenue; and
- $17 million of lower wholesale revenue due to reduced volumes and lower average wholesale prices.

Operations and maintenance increased $31 million, or 13%, for the second quarter of 2015 compared to 2014 primarily due to recognition in 2014 of insurance recoveries expected from the Sanpete County, Utah rangeland fire.

Depreciation and amortization increased $13 million, or 7%, for the second quarter of 2015 compared to 2014 primarily due to higher plant in-service, including Lake Side 2.

Taxes, other than income taxes increased $5 million, or 13%, for the second quarter of 2015 compared to 2014 due to higher property taxes primarily from higher assessed property values.

Allowance for borrowed and equity funds decreased $8 million, or 38%, for the second quarter of 2015 compared to 2014 primarily due to lower qualified construction work-in-progress balances.

Income tax expense decreased $9 million, or 11%, for the second quarter of 2015 compared to 2014 and the effective tax rate was 30% and 31% for the second quarter of 2015 and 2014, respectively. The decrease in income tax expense was primarily due to lower pre-tax book income.

Gross margin increased $23 million, or 1%, for the first six months of 2015 compared to 2014 primarily due to:

- $74 million of increases mainly from higher retail rates;
- $70 million of lower natural gas costs primarily due to decreased generation primarily as a result of reduced economical dispatch and lower average unit costs, partially offset by increased generation from the addition of Lake Side 2; and
- $13 million of lower purchased electricity due to lower average market prices, partially offset by higher volumes.

The increase in gross margin was partially offset by:

- $30 million of higher coal costs due to higher average unit costs and higher volumes;
- $29 million of lower wholesale revenue primarily due to reduced volumes;
- $29 million of lower REC revenue;
- $25 million of lower retail revenues from a 1.0% decrease in retail customer load, with 1.8% lower customer usage by residential, irrigation and commercial customers, partially offset by a 0.7% increase in the average number of residential customers in Utah and Oregon and commercial customers in Utah. The impacts of the hot weather in June 2015 on residential and commercial customers were largely offset by the impacts of mild weather in the first quarter of 2015 on residential and commercial customers primarily in Oregon and Washington; and
- $24 million of lower net deferrals of incurred net power costs in accordance with established adjustment mechanisms.

Operations and maintenance increased $26 million, or 5%, for the first six months of 2015 compared to 2014 due to recognition in 2014 of insurance recoveries expected from the Sanpete County, Utah rangeland fire.

Depreciation and amortization increased $23 million, or 6%, for the first six months of 2015 compared to 2014 primarily due to higher plant in-service, including Lake Side 2.

Taxes, other than income taxes increased $8 million, or 10%, for the first six months of 2015 compared to 2014 due to higher property taxes primarily from higher plant placed in-service and higher assessed property values.

Allowance for borrowed and equity funds decreased $16 million, or 36%, for the first six months of 2015 compared to 2014 primarily due to lower qualified construction work-in-progress balances.

Income tax expense decreased $13 million, or 9%, for the first six months of 2015 compared to 2014 and the effective tax rate was 31% for the first six months of 2015 and 2014. The decrease in income tax expense was primarily due to lower pre-tax book income.

Liquidity and Capital Resources

As of June 30, 2015, PacifiCorp's total net liquidity was as follows (in millions):

Cash and cash equivalents	$ 96
Credit facilities	1,200
Less:	
Short-term debt	—
Letters of credit and tax-exempt bond support	(206)
Net credit facilities	994
Total net liquidity	$ 1,090
Credit facilities:	
Maturity dates	2017, 2018

Operating Activities

Net cash flows from operating activities for the six-month periods ended June 30, 2015 and 2014 were $987 million and $886 million, respectively. The $101 million increase was primarily due to cash received for income taxes in the current year compared to cash paid for income taxes in the prior year and lower purchased electricity and fuel payments, partially offset by increases in cash collateral posted for derivative contracts, lower collections from retail customers and lower receipts from wholesale electricity sales.

In December 2014, the Tax Increase Prevention Act of 2014 (the "Act") was signed into law, extending the 50% bonus depreciation for qualifying property purchased and placed in-service before January 1, 2015 and before January 1, 2016 for certain longer-lived assets. As a result of the Act, PacifiCorp's cash flows from operations are benefiting in 2015 due to bonus depreciation on qualifying assets placed in-service.

Investing Activities

Net cash flows from investing activities for the six-month periods ended June 30, 2015 and 2014 were $(441) million and $(535) million, respectively. The change was primarily due to a decrease in capital expenditures of $113 million. Refer to "Future Uses of Cash" for discussion of capital expenditures.

Financing Activities

Net cash flows from financing activities for the six-month period ended June 30, 2015 was $(473) million. Uses of cash consisted substantially of $700 million for common stock dividends paid to PPW Holdings and $20 million for the repayment of short-term debt. Sources of cash consisted of proceeds from the issuance of long-term debt of $250 million.

Net cash flows from financing activities for the six-month period ended June 30, 2014 was $(216) million. Uses of cash consisted substantially of $625 million for common stock dividends paid to PPW Holdings and $12 million for the repayment of long-term debt. Sources of cash consisted of proceeds from the issuance of long-term debt of $425 million.

Short-term Debt

Regulatory authorities limit PacifiCorp to $1.5 billion of short-term debt. As of June 30, 2015, PacifiCorp had no short-term debt outstanding. As of December 31, 2014, PacifiCorp had $20 million of short-term debt outstanding at a weighted average interest rate of 0.43%.

Long-term Debt

In June 2015, PacifiCorp issued $250 million of its 3.35% First Mortgage Bonds due July 2025. The net proceeds were used to fund capital expenditures and for general corporate purposes, including retirement of short-term debt.

PacifiCorp currently has regulatory authority from the OPUC and the IPUC to issue an additional $1.325 billion of long-term debt. PacifiCorp must make a notice filing with the WUTC prior to any future issuance.

Future Uses of Cash

PacifiCorp has available a variety of sources of liquidity and capital resources, both internal and external, including net cash flows from operating activities, public and private debt offerings, the issuance of commercial paper, the use of unsecured revolving credit facilities, capital contributions and other sources. These sources are expected to provide funds required for current operations, capital expenditures, debt retirements and other capital requirements. The availability and terms under which PacifiCorp has access to external financing depends on a variety of factors, including PacifiCorp's credit ratings, investors' judgment of risk and conditions in the overall capital markets, including the condition of the utility industry.

Capital Expenditures

PacifiCorp has significant future capital requirements. Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, changes in environmental and other rules and regulations; impacts to customers' rates; outcomes of regulatory proceedings; changes in income tax laws; general business conditions; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; commodity prices; and the cost and availability of capital. Prudently incurred expenditures for compliance-related items, such as pollution-control technologies, replacement generation, hydroelectric relicensing, hydroelectric decommissioning and associated operating costs are generally incorporated into PacifiCorp's rates.

Historical and forecast capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items, are as follows (in millions):

	Six-Month Periods Ended June 30, 2014	Six-Month Periods Ended June 30, 2015	Annual Forecast 2015
Transmission system investment	$ 122	$ 64	$ 145
Environmental	83	51	134
Lake Side 2	31	—	—
Other	296	304	645
Total	$ 532	$ 419	$ 924

PacifiCorp's historical and forecast capital expenditures include the following:

- Transmission system investment includes construction costs for the 170-mile single-circuit 345-kV Sigurd-Red Butte transmission line that was placed in-service in May 2015.

- Environmental includes the installation of new or the replacement of existing emissions control equipment at certain generating facilities, including installation or upgrade of selective catalytic reduction control systems and low-nitrogen oxide burners to reduce nitrogen oxides, particulate matter control systems and mercury emissions control systems.

- Remaining investments relate to operating projects that consist of routine expenditures for transmission, distribution, generation and other infrastructure needed to serve existing and expected demand.

PacifiCorp and the California ISO Memorandum of Understanding

In April 2015, PacifiCorp and the California Independent System Operator Corporation ("California ISO") entered into a non-binding memorandum of understanding to explore the feasibility, costs and benefits of PacifiCorp joining the California ISO as a participating transmission owner. A comprehensive benefits study is underway and is expected to be completed by late September 2015. Should PacifiCorp decide to take additional steps to pursue joining the California ISO, a stakeholder input and review process would be initiated and PacifiCorp would seek necessary regulatory approvals, including from its state regulatory commissions and the FERC.

PacifiCorp and the California ISO launched the regional energy imbalance market in November 2014, which allows PacifiCorp to participate in the California ISO's real-time energy markets to most cost-effectively manage short-term fluctuations in energy supply and demand. Joining the California ISO would extend that participation by PacifiCorp into the day-ahead energy market operated by the California ISO, in addition to unified planning and operation of PacifiCorp's transmission network.

Contractual Obligations

As of June 30, 2015, there have been no material changes outside the normal course of business in contractual obligations from the information provided in Item 7 of PacifiCorp's Annual Report on Form 10-K for the year ended December 31, 2014.

Regulatory Matters

PacifiCorp is subject to comprehensive regulation. The discussion below contains material developments to those matters disclosed in Item 7 of PacifiCorp's Annual Report on Form 10-K for the year ended December 31, 2014, and new regulatory matters occurring in 2015.

State Regulatory Matters

Utah Mine Disposition

In December 2014, PacifiCorp filed applications with the UPSC, the OPUC, the WPSC and the IPUC seeking certain approvals, prudence determinations and accounting orders to close PacifiCorp's Deer Creek mining operations, sell certain Utah mining assets, enter into a replacement coal supply agreement, amend an existing coal supply agreement, withdraw from the United Mine Workers of America ("UMWA") 1974 Pension Plan and settle PacifiCorp's other postretirement benefit obligation for UMWA participants (collectively, the "Utah Mine Disposition"). PacifiCorp also filed an advice letter with the CPUC.

In April 2015, PacifiCorp filed all-party settlement stipulations with the UPSC and the WPSC finding that the decision to enter into the Utah Mine Disposition transaction is prudent and in the public interest and recommending the appropriate treatment for accounting and ratemaking purposes. The UPSC approved the stipulation in April 2015 and the WPSC approved the stipulation in May 2015. The IPUC also issued an order in May 2015, approving the Utah Mine Disposition and ruling that the decision to enter into the transaction was prudent and in the public interest. The IPUC's order established the accounting treatment necessary to implement the transaction while deferring any incremental ratemaking treatment to the next general rate case.

In May 2015, the OPUC issued its final order in the Utah Mine Disposition transaction proceeding, concluding that the transaction produces net benefits for customers and is in the public interest. In accordance with the OPUC order, PacifiCorp implemented two tariffs that reflect an overall annual rate increase of $3 million effective June 2015.

Utah

In March 2015, PacifiCorp filed its annual Energy Balancing Account with the UPSC requesting recovery of $31 million in deferred net power costs for the period January 1, 2014 through December 31, 2014. If approved by the UPSC, the new rates will be effective November 2015.

In March 2015, PacifiCorp filed its annual REC balancing account application with the UPSC requesting recovery of $6 million over a two-year period. In May 2015, the UPSC approved the new rates effective June 2015 on an interim basis until a final order is issued by the UPSC.

Oregon

In April 2015, PacifiCorp made its initial filing for the annual Transition Adjustment Mechanism with the OPUC for an annual increase of $12 million, or an average price increase of 1%, based on forecasted net power costs for calendar year 2016. The filing will be subject to updates throughout the year. If approved by the OPUC, the new rates will be effective January 2016.

Wyoming

In March 2015, PacifiCorp filed a general rate case with the WPSC requesting an annual increase of $32 million, or an average price increase of 5%, effective January 2016. The filing includes a proposal to implement a modified Energy Cost Adjustment Mechanism ("ECAM") to replace the current ECAM, which sunsets for new deferrals December 2015. In June 2015, PacifiCorp filed a net power cost update reducing the requested increase to $30 million, or an average price increase of 4%.

In March 2015, PacifiCorp filed its annual ECAM and Renewable Energy Credit and Sulfur Dioxide Revenue Adjustment Mechanism ("RRA") applications with the WPSC. The ECAM filing requests approval to recover $8 million in deferred net power costs for the period January 1, 2014 through December 31, 2014, and the RRA application requests approval to refund $1 million to customers. In May 2015, the WPSC approved the ECAM and RRA rates effective May 2015 on an interim basis until a final order is issued by the WPSC.

Washington

In May 2014, PacifiCorp filed a general rate case with the WUTC requesting an annual increase of $27 million, or an average price increase of 8%. In November 2014, PacifiCorp filed rebuttal testimony that increased the request to $32 million, or an average price increase of 10%, primarily as a result of updated net power costs. In March 2015, the WUTC issued a final order in the proceeding approving an overall annual increase of $10 million, or an average price increase of 3%, effective March 2015. In April 2015, PacifiCorp filed a petition for judicial review of certain findings of the WUTC's March 2015 order.

In the March 2015 general rate case order described above, the WUTC initiated a second phase of the proceeding to implement a Power Cost Adjustment Mechanism ("PCAM") under which a portion of the difference between base net power costs set during a general rate case and actual net power costs would be deferred and reflected in future rates. In May 2015, the WUTC approved an all-party stipulation in which the parties agreed to the implementation of a PCAM. The PCAM applies a $4 million dead band for positive or negative net power cost variances. For net power cost variances between $4 million and $10 million, the PCAM reflects asymmetrical sharing bands in which amounts to be recovered from customers will be allocated 50% to customers and 50% to PacifiCorp, and amounts to be credited to customers will be allocated 75% to customers and 25% to PacifiCorp. Positive or negative net power cost variances in excess of $10 million will be allocated 90% to customers and 10% to PacifiCorp. PacifiCorp will make its first annual PCAM filing in June 2016 to cover net power costs for the period April 1, 2015 through December 31, 2015. The PCAM will convert to a calendar year basis beginning in 2016.

Idaho

In February 2015, PacifiCorp filed its annual ECAM application with the IPUC requesting recovery of $17 million, consisting primarily of $10 million for deferred net power costs and $6 million for the difference between REC revenues included in base rates and actual REC revenues. In March 2015, the IPUC approved recovery of $16 million effective April 2015.

In May 2015, PacifiCorp filed an application with the IPUC requesting approval to modify the ECAM, update base net power costs and increase rates by $10 million, effective January 2016. The requested increase includes $7 million for the difference between REC revenues included in base rates and actual REC revenues, and $3 million as a result of updating base net power costs.

California

In August 2014, PacifiCorp filed for a rate increase of $5 million, or 4%, through its annual Energy Cost Adjustment Clause ("ECAC"). The CPUC approved the new rates effective March 2015.

In June 2015, PacifiCorp filed for a rate increase of $1 million, or 1%, through its Post Test-year Adjustment Mechanism for major capital additions to add the Sigurd-Red Butte transmission line to rates. The new rates were effective July 2015.

In August 2015, PacifiCorp filed for a rate decrease of $2 million, or 2%, through its annual ECAC. If approved by the CPUC, the new rates will be effective January 2016.

Environmental Laws and Regulations

PacifiCorp is subject to federal, state and local laws and regulations regarding air and water quality, renewable portfolio standards, emissions performance standards, climate change, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact PacifiCorp's current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance including fines, injunctive relief and other sanctions. These laws and regulations are administered by the EPA and various state and local agencies. PacifiCorp believes it is in material compliance with all applicable laws and regulations, although many are subject to interpretation that may ultimately be resolved by the courts. Refer to "Liquidity and Capital Resources" for discussion of PacifiCorp's forecast environmental-related capital expenditures. The discussion below contains material developments to those matters disclosed in Item 7 of PacifiCorp's Annual Report on Form 10-K for the year ended December 31, 2014.

Clean Air Act Regulations

Mercury and Air Toxics Standards

Numerous lawsuits have been filed in the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") challenging the Mercury and Air Toxics Standards ("MATS"). In April 2014, the D.C. Circuit upheld the MATS requirements. In November 2014, the United States Supreme Court agreed to hear the MATS appeal on the limited issue of whether the EPA unreasonably refused to consider costs in determining whether it is appropriate to regulate hazardous air pollutants emitted by electric utilities. Oral argument in the case was held before the United States Supreme Court in March 2015, and a decision was issued by the United States Supreme Court in June 2015, which reversed and remanded the MATS rule to the D.C. Circuit for further action. The United States Supreme Court held that the EPA had acted unreasonably when it deemed cost irrelevant to the decision to regulate generating facilities, and that cost, including costs of compliance, must be considered before deciding whether regulation is necessary and appropriate. The United States Supreme Court's decision did not vacate or stay implementation of the MATS rule and until the D.C. Circuit takes further action, PacifiCorp continues to have a legal obligation under the MATS rule and its permits issued by the states in which it operates to comply with the MATS rule, including operating all emissions controls or otherwise complying with the MATS requirements, such as idling the Carbon coal-fueled generating facility ("Carbon Facility"). Refer to the Regional Haze section below for additional requirements regarding the Carbon Facility.

Regional Haze

The state of Utah issued a regional haze State Implementation Plan ("SIP") requiring the installation of sulfur dioxide, nitrogen oxides and particulate matter controls on Hunter Units 1 and 2, and Huntington Units 1 and 2. In December 2012, the EPA approved the sulfur dioxide portion of the Utah regional haze SIP and disapproved the nitrogen oxides and particulate matter portions. Certain groups appealed the EPA's approval of the sulfur dioxide portion and oral argument was heard before the United States Court of Appeals for the Tenth Circuit ("Tenth Circuit") in March 2014. In October 2014, the Tenth Circuit upheld the EPA's approval of the sulfur dioxide portion of the SIP. The state of Utah and PacifiCorp filed petitions for administrative and judicial review of the EPA's final rule on the best available retrofit technology ("BART") determinations for the nitrogen oxides and particulate matter portions of Utah's regional haze SIP in March 2013. Oral argument was held before the Tenth Circuit in March 2014. In May 2014, the Tenth Circuit dismissed the petition on jurisdictional grounds. In addition, and separate from the EPA's approval process and related litigation, the Utah Division of Air Quality has undertaken an additional BART analysis for Hunter Units 1 and 2, and Huntington Units 1 and 2. The additional BART analysis and revised regional haze SIP was submitted in June 2015 to the EPA for review and proposed action after a public comment period. The revised regional haze SIP includes a state-enforceable requirement to retire the Carbon Facility by August 15, 2015, and PacifiCorp has begun to make plans for decommissioning. This requirement is independent of the requirements of the MATS rule as discussed above. The EPA is expected to review and take final action on the SIP in 2016. It is unknown how the EPA's decision regarding the Utah SIP may impact PacifiCorp's obligations under the regional haze requirements.

The state of Arizona issued a regional haze SIP requiring, among other things, the installation of sulfur dioxide, nitrogen oxides and particulate matter controls on Cholla Unit 4. The EPA approved in part, and disapproved in part, the Arizona SIP and issued a Federal Implementation Plan ("FIP") for the disapproved portions requiring selective catalytic reduction controls on Cholla Unit 4. PacifiCorp filed an appeal in the United States Court of Appeals for the Ninth Circuit ("Ninth Circuit") regarding the FIP as it relates to Cholla Unit 4, and the Arizona Department of Environmental Quality and other affected Arizona utilities filed separate appeals of the FIP as it relates to their interests. The Ninth Circuit issued an order in February 2015, holding the matter in abeyance relating to PacifiCorp and Arizona Public Service Company as they work with state and federal agencies on an alternate compliance approach for Cholla Unit 4. In January 2015, Arizona Public Service Company submitted the permit applications and studies required to amend the Title V permit, and subsequently the Arizona SIP to convert Cholla Unit 4 to a natural gas-fueled unit in 2025. The Arizona Department of Environmental Quality prepared a draft permit and a revision to the Arizona regional haze SIP, held two public hearings in July 2015 and, after considering the comments received during the public comment period that closed on July 14, 2015, will submit final proposals to the EPA for review, public comment and final action.

Climate Change

GHG Performance Standards

Under the Clean Air Act, the EPA may establish emissions standards that reflect the degree of emissions reductions achievable through the best technology that has been demonstrated, taking into consideration the cost of achieving those reductions and any non-air quality health and environmental impact and energy requirements. The EPA entered into a settlement agreement with a number of parties, including certain state governments and environmental groups, in December 2010 to promulgate emissions standards covering GHG. In April 2012, the EPA proposed new source performance standards for new fossil-fueled generating facilities that would limit emissions of carbon dioxide to 1,000 pounds per MWh. As part of his Climate Action Plan, President Obama announced a national climate change strategy and issued a presidential memorandum requiring the EPA to issue a re-proposed GHG new source performance standard for fossil-fueled generating facilities by September 2013. The September 2013 GHG new source performance standards released by the EPA set different standards for coal-fueled and natural gas-fueled generating facilities. The proposed standard for natural gas-fueled generating facilities considered the size of the unit and the electricity sent to the grid from the unit. The proposed standards were published in the Federal Register January 8, 2014, and the public comment period closed in May 2014. On August 3, 2015, the EPA issued the final new source performance standards, establishing a standard of 1,000 pounds of carbon dioxide per MWh for large natural gas-fueled generating facilities and 1,400 pounds of carbon dioxide per MWh for new coal-fueled generating facilities with the "Best System of Emission Reduction" for coal-fueled generating facilities reflecting highly efficient supercritical pulverized coal facilities with partial carbon capture and sequestration or integrated gasification combined-cycle units that are co-fired with natural gas or pre-combustion slipstream capture of carbon dioxide. Any new fossil-fueled generating facilities constructed by PacifiCorp will be required to meet the GHG new source performance standards.

In June 2014, the EPA released proposed regulations to address GHG emissions from existing fossil-fueled generating facilities, referred to as the Clean Power Plan, under Section 111(d) of the Clean Air Act. The EPA's proposal calculated state-specific emission rate targets to be achieved based on four building blocks that it determined were the "Best System of Emission Reduction." The four building blocks include: (a) a 6% heat rate improvement from coal-fueled generating facilities; (b) increased utilization of existing combined-cycle natural gas-fueled generating facilities to 70%; (c) increased deployment of renewable and non-carbon generating resources; and (d) increased energy efficiency. Under this proposal, states could have utilized any measure to achieve the specified emission reduction goals, with an initial implementation period of 2020-2029 and the final goal to be achieved by 2030. When fully implemented, the proposal was expected to reduce carbon dioxide emissions in the power sector to 30% below 2005 levels by 2030. The final Clean Power Plan was released August 3, 2015 and changed the methodology upon which the Best System of Emission Reduction is based to include: (a) heat rate improvements; (b) increased utilization of existing combined-cycle natural gas-fueled generating facilities; and (c) increased deployment of new and incremental non-carbon generation placed in-service after 2012. The EPA also changed the compliance period to begin in 2022, with three interim periods of compliance and with the final goal to be achieved by 2030. Based on changes to the state emission reduction targets, which are now all between 771 pounds per MWh and 1,305 pounds per MWh, the Clean Power Plan, when fully implemented, is expected to reduce carbon dioxide emissions in the power sector to 32% below 2005 levels by 2030. The EPA also released on August 3, 2015, a draft federal plan as an option or backstop for states to utilize in the event they do not submit approvable state plans. The draft federal plan is expected to be open for a 90-day public comment period after publication in the Federal Register. States are required to submit initial implementation plans by September 2016, and may request an extension to September 2018. The impacts of the final rule or the federal plan on PacifiCorp cannot be determined until the states develop their implementation plans or the federal plan is finalized. PacifiCorp has historically pursued cost-effective projects, including plant efficiency improvements, increased diversification of its generating fleets to include deployment of renewable and lower carbon generating resources, and advancement of customer energy efficiency programs.

The GHG rules and PacifiCorp's compliance requirements are subject to potential outcomes from proceedings and litigation challenging the rules.

Coal Combustion Byproduct Disposal

In May 2010, the EPA released a proposed rule to regulate the management and disposal of coal combustion byproducts, presenting two alternatives to regulation under the Resource Conservation and Recovery Act ("RCRA"). The public comment period closed in November 2010. The final rule was released by the EPA on December 19, 2014, was published in the Federal Register on April 17, 2015 and will be effective on October 19, 2015. The final rule regulates coal combustion byproducts as non-hazardous waste under RCRA Subtitle D and establishes minimum nationwide standards for the disposal of coal combustion residuals. Under the final rule, surface impoundments and landfills utilized for coal combustion byproducts may need to be closed unless they can meet the more stringent regulatory requirements.

As defined by the final rule, PacifiCorp operates 18 surface impoundments and seven landfills that contain coal combustion byproducts. Refer to Note 7 for discussion of the impacts on asset retirement obligations as a result of the final rule.

Collateral and Contingent Features

Debt and preferred securities of PacifiCorp are rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of PacifiCorp's ability to, in general, meet the obligations of its issued debt or preferred securities. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time. As of June 30, 2015, PacifiCorp's credit ratings for its senior secured debt and its issuer credit ratings for senior unsecured debt from the three recognized credit rating agencies were investment grade.

PacifiCorp has no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt and a change in ratings is not an event of default under the applicable debt instruments. PacifiCorp's unsecured revolving credit facilities do not require the maintenance of a minimum credit rating level in order to draw upon their availability. However, commitment fees and interest rates under the credit facilities are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities. Certain authorizations or exemptions by regulatory commissions for the issuance of securities are valid as long as PacifiCorp maintains investment grade ratings on senior secured debt. A downgrade below that level would necessitate new regulatory applications and approvals.

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain credit support provisions that in part base certain collateral requirements on credit ratings for senior unsecured debt as reported by one or more of the three recognized credit rating agencies. These agreements may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance" in the event of a material adverse change in PacifiCorp's creditworthiness. These rights can vary by contract and by counterparty. If all credit-risk-related contingent features or adequate assurance provisions for these agreements had been triggered as of June 30, 2015, PacifiCorp would have been required to post $252 million of additional collateral. PacifiCorp's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors. Refer to Note 8 of Notes to Consolidated Financial Statements in Item 1 of this Form 10-Q for a discussion of PacifiCorp's collateral requirements specific to PacifiCorp's derivative contracts.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting PacifiCorp, refer to Note 2 of Notes to Consolidated Financial Statements in Item 1 of this Form 10-Q.

Critical Accounting Estimates

Certain accounting measurements require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized on the Consolidated Financial Statements based on such estimates involve numerous assumptions subject to varying and potentially significant degrees of judgment and uncertainty and will likely change in the future as additional information becomes available. Estimates are used for, but not limited to, the accounting for the effects of certain types of regulation, derivatives, pension and other postretirement benefits, income taxes and revenue recognition - unbilled revenue. For additional discussion of PacifiCorp's critical accounting estimates, see Item 7 of PacifiCorp's Annual Report on Form 10-K for the year ended December 31, 2014. There have been no significant changes in PacifiCorp's assumptions regarding critical accounting estimates since December 31, 2014.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

For quantitative and qualitative disclosures about market risk affecting PacifiCorp, see Item 7A of PacifiCorp's Annual Report on Form 10-K for the year ended December 31, 2014. PacifiCorp's exposure to market risk and its management of such risk has not changed materially since December 31, 2014. Refer to Note 8 of Notes to Consolidated Financial Statements in Item 1 of this Form 10-Q for disclosure of PacifiCorp's derivative positions as of June 30, 2015.

Item 4. Controls and Procedures

At the end of the period covered by this Quarterly Report on Form 10-Q, PacifiCorp carried out an evaluation, under the supervision and with the participation of PacifiCorp's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), of the effectiveness of the design and operation of PacifiCorp's disclosure controls and procedures (as defined in Rule 13a-15(e) promulgated under the Securities and Exchange Act of 1934, as amended). Based upon that evaluation, PacifiCorp's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), concluded that PacifiCorp's disclosure controls and procedures were effective to ensure that information required to be disclosed by PacifiCorp in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the United States Securities and Exchange Commission's rules and forms, and is accumulated and communicated to management, including PacifiCorp's Chief Executive Officer (principal executive officer) and Chief Financial Officer (principal financial officer), or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. There has been no change in PacifiCorp's internal control over financial reporting during the quarter ended June 30, 2015 that has materially affected, or is reasonably likely to materially affect, PacifiCorp's internal control over financial reporting.

PART II

Item 1. Legal Proceedings

For a description of certain legal proceedings affecting PacifiCorp, refer to Note 10 of Notes to Consolidated Financial Statements included in Part I, Item 1 of this Form 10-Q.

Item 1A. Risk Factors

There has been no material change to PacifiCorp's risk factors from those disclosed in Item 1A of PacifiCorp's Annual Report on Form 10-K for the year ended December 31, 2014.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Not applicable.

Item 3. Defaults Upon Senior Securities

Not applicable.

Item 4. Mine Safety Disclosures

Information regarding PacifiCorp's mine safety violations and other legal matters disclosed in accordance with Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act is included in Exhibit 95 to this Form 10-Q.

Item 5. Other Information

Not applicable.

Item 6. Exhibits

The exhibits listed on the accompanying Exhibit Index are filed as part of this Quarterly Report.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PACIFICORP

(Registrant)

Date: August 7, 2015

/s/ Douglas K. Stuver

Douglas K. Stuver

Senior Vice President and Chief Financial Officer

(principal financial and accounting officer)

EXHIBIT INDEX

Exhibit No.	Description
4.1*	Twenty-Eighth Supplemental Indenture, dated as of June 1, 2015, to PacifiCorp's Mortgage and Deed of Trust dated as of January 9, 1989 (Exhibit 4.1, Current Report on Form 8-K, filed June 19, 2015, File No. 1-5152).
15	Awareness Letter of Independent Registered Public Accounting Firm.
31.1	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95	Mine Safety Disclosures Required by the Dodd-Frank Wall Street Reform and Consumer Protection Act.
101	The following financial information from PacifiCorp's Quarterly Report on Form 10-Q for the quarter ended June 30, 2015 is formatted in XBRL (eXtensible Business Reporting Language) and included herein: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Changes in Shareholders' Equity, (iv) the Consolidated Statements of Cash Flows, and (v) the Notes to Consolidated Financial Statements, tagged in summary and detail.

*Incorporated by reference.

EXHIBIT 15

August 7, 2015

To the Board of Directors and Shareholders of
PacifiCorp
Portland, Oregon

We have reviewed, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the unaudited consolidated interim financial information of PacifiCorp and subsidiaries for the periods ended June 30, 2015 and 2014, as indicated in our report dated August 7, 2015; because we did not perform an audit, we expressed no opinion on that information.

We are aware that our report referred to above, which is included in your Quarterly Report on Form 10-Q for the quarter ended June 30, 2015, is incorporated by reference in Registration Statement No. 333-192267 on Form S-3ASR.

We also are aware that the aforementioned report, pursuant to Rule 436(c) under the Securities Act of 1933, is not considered a part of the Registration Statement prepared or certified by an accountant or a report prepared or certified by an accountant within the meaning of Sections 7 and 11 of that Act.

/s/ Deloitte & Touche LLP

Portland, Oregon

EXHIBIT 31.1

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Gregory E. Abel, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PacifiCorp;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 7, 2015

/s/ Gregory E. Abel
Gregory E. Abel
Chairman of the Board of Directors and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.2

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Douglas K. Stuver, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PacifiCorp;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 7, 2015

/s/ Douglas K. Stuver
Douglas K. Stuver
Senior Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 32.1

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Gregory E. Abel, Chairman of the Board of Directors and Chief Executive Officer of PacifiCorp, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Quarterly Report on Form 10-Q of the Company for the quarterly period ended June 30, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o (d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: August 7, 2015

/s/ Gregory E. Abel
Gregory E. Abel
Chairman of the Board of Directors and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.2

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Douglas K. Stuver, Senior Vice President and Chief Financial Officer of PacifiCorp, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Quarterly Report on Form 10-Q of the Company for the quarterly period ended June 30, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o (d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: August 7, 2015

/s/ Douglas K. Stuver
Douglas K. Stuver
Senior Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 95

MINE SAFETY VIOLATIONS AND OTHER LEGAL MATTER DISCLOSURES PURSUANT TO SECTION 1503(a) OF THE DODD-FRANK WALL STREET REFORM AND CONSUMER PROTECTION ACT

PacifiCorp and its subsidiaries operate certain coal mines and coal processing facilities (collectively, the "mining facilities") that are regulated by the Federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 (the "Mine Safety Act"). MSHA inspects PacifiCorp's mining facilities on a regular basis. The total number of reportable Mine Safety Act citations, orders, assessments and legal actions for the three-month period ended June 30, 2015 are summarized in the table below and are subject to contest and appeal. The severity and assessment of penalties may be reduced or, in some cases, dismissed through the contest and appeal process. Amounts are reported regardless of whether PacifiCorp has challenged or appealed the matter. Coal reserves that are not yet mined and mines that are closed or idled are not included in the information below if no reportable events occurred at those locations during the three-month period ended June 30, 2015. There were no mining-related fatalities during the three-month period ended June 30, 2015. PacifiCorp has not received any notice of a pattern, or notice of the potential to have a pattern, of violations of mandatory health or safety standards that are of such nature as could have significantly and substantially contributed to the cause and effect of coal or other mine health or safety hazards under Section 104(e) of the Mine Safety Act during the three-month period ended June 30, 2015.

	Mine Safety Act						Legal Actions		
Mining Facilities	Section 104 Significant and Substantial Citations(1)	Section 104(b) Orders(2)	Section 104(d) Citations/ Orders(3)	Section 110(b)(2) Violations(4)	Section 107(a) Imminent Danger Orders(5)	Total Value of Proposed MSHA Assessments (in thousands)	Pending as of Last Day of Period(6)	Instituted During Period	Resolved During Period
Deer Creek(7)	—	—	—	—	—	$ 5	1	—	1
Bridger (surface)	3	—	—	—	—	9	3	—	2
Bridger (underground)	9	—	—	—	—	98	5	2	5
Cottonwood Preparatory Plant(8)	—	—	—	—	—	—	—	—	—
Wyodak Coal Crushing Facility	—	—	—	—	—	—	—	—	—

(1) Citations for alleged violations of mandatory health and safety standards that could significantly or substantially contribute to the cause and effect of a safety or health hazard under Section 104 of the Mine Safety Act.

(2) For alleged failure to totally abate the subject matter of a Mine Safety Act Section 104(a) citation within the period specified in the citation.

(3) For alleged unwarrantable failure (i.e., aggravated conduct constituting more than ordinary negligence) to comply with a mandatory health or safety standard.

(4) For alleged flagrant violations (i.e., reckless or repeated failure to make reasonable efforts to eliminate a known violation of a mandatory health or safety standard that substantially and proximately caused, or reasonably could have been expected to cause, death or serious bodily injury).

(5) For the existence of any condition or practice in a coal or other mine which could reasonably be expected to cause death or serious physical harm before such condition or practice can be abated.

(6) Amounts include six contests of proposed penalties under Subpart C and three contests of citations or orders under Subpart B of the Federal Mine Safety and Health Review Commission's procedural rules. The pending legal actions are not exclusive to citations, notices, orders and penalties assessed by MSHA during the reporting period.

(7) The Deer Creek mine is currently idled and closure activities have begun.

(8) The Cottonwood Preparatory Plant was sold in June 2015.

EXHIBIT E

DECLARATION OF NATALIE COOPER REGARDING THE NEWSPAPER PUBLICATION LIMITATIONS IN PROJECT AREA

DECLARATION OF NATALIE COOPER
REGARDING THE NEWSPAPER PUBLICATION LIMITATIONS
IN THE PROJECT AREA

I, Natalie Cooper, state:

1. I am an Administrative Services Coordinator for PacifiCorp.
2. PacifiCorp is filing its application for a Permit to Construct the Lassen Substation Project on November 2, 2015.
3. PacifiCorp is required to file notice of such application (Notice) in a newspaper of general circulation in the area of the project within ten days of submitting the application. The Notice must contain the application number assigned to it by the California Public Utilities Commission.
4. The newspaper of general circulation in the Project area in which the notice will be published is the Mt. Shasta Herald, Dunsmuir News and Weed Press (Mt. Shasta Herald).
5. The Mt. Shasta Herald is published once a week on Wednesday.
6. Advertising space to publish the Notice must be reserved by Thursday of the week prior to publication.
7. A final copy of the Notice must be submitted to the paper by Monday at noon of the week of publication.
8. If an application number is assigned by Thursday, November 5, 2015, the Notice may be submitted to the newspaper by Monday, November 9, 2015. The first week of publication would occur on Wednesday, November 11, 2015. The second week of publication would occur on Wednesday, November 18, 2015.

9. If an application number is received after Friday, November 6, 2015, the publication dates will be delayed by one week.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct to the best of my knowledge and belief.

Date: November 2, 2015.

Natalie Cooper

Natalie Cooper
Administrative Services Coordinator
PacifiCorp