SOAH DOCKET NO. 473-19-3864
PUC DOCKET NO. 49421 2019 MAY 17 PM 2:27

APPLICATION OF CENTERPOINT	**§**	**BEFORE THE STATE OFFICE**
ENERGY HOUSTON ELECTRIC, LLC	**§**	**OF**
FOR AUTHORITY TO CHANGE RATES	**§**	**ADMINISTRATIVE HEARINGS**

May 17, 2019

Contact: Denise Hardcastle
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CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
2019 CEHE RATE CASE
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PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-01

QUESTION:

Regarding the Company's proposal to reduce the standard allowance for contributions in aid of construction related to Electric Vehicle charging stations, has the Company included any adjustments to its cost of service and rate requests in this proceeding associated with this proposal? If so, please identify all such adjustments by FERC account, or subaccount where such subaccount is used anywhere in the rate filing package, and indicate where in the rate filing package such adjustments can be found.

ANSWER:

CenterPoint Houston has not included any adjustments to its cost of service or rate requests in this proceeding associated with the proposal to reduce the standard allowance for contributions in aid of construction related to Electric Vehicle charging stations.

SPONSOR (PREPARER):
Kristie Colvin/Matthew Troxle (Kristie Colvin/Matthew Troxle)

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
2019 CEHE RATE CASE
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PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-02

QUESTION:

Regarding the Company's request for authority to install voltage smoothing battery systems and to include the associated costs in base rates, has the Company included any adjustments to its cost of service and rate requests in this proceeding associated with this proposal? If so, please identify all such adjustments by FERC account, or subaccount where such subaccount is used anywhere in the rate filing package, and indicate where in the rate filing package such adjustments can be found.

ANSWER:

CenterPoint Houston did not include any adjustments to its cost of service or rate requests in this proceeding associated with costs to install voltage smoothing battery systems.

SPONSOR (PREPARER):
Kristie Colvin/Matthew Troxle (Kristie Colvin/Matthew Troxle)

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
2019 CEHE RATE CASE
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PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-03

QUESTION:

For each month of the Test Year, please provide the peak demand on the Welsh DC tie when the direction of the energy flow was into ERCOT.

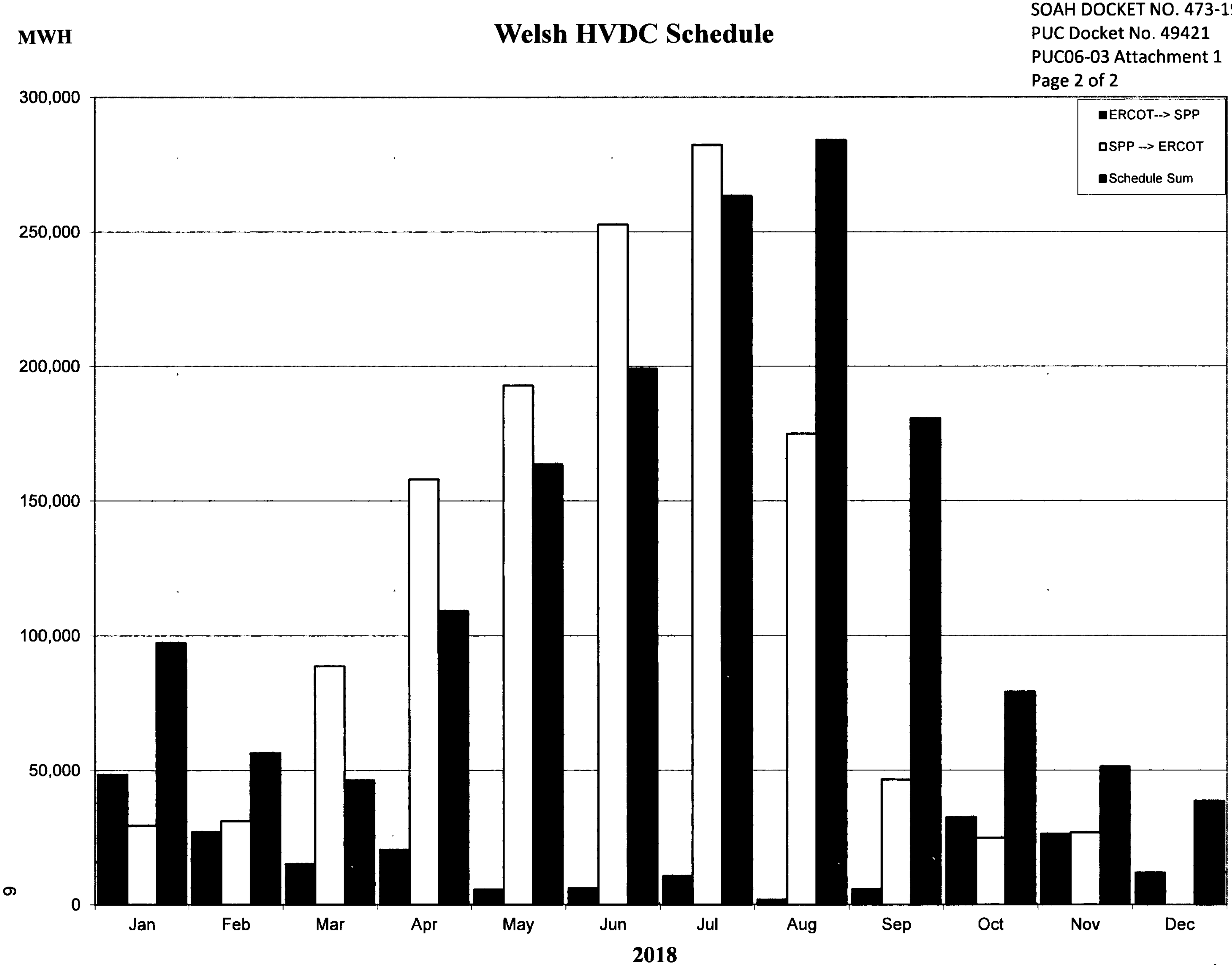
ANSWER:

The Welsh DC tie is a scheduled device that does not respond to demand or load on either ERCOT or SPP's system. Attached is the monthly delivery schedule for energy flow in and out of ERCOT over the tie.

SPONSOR (PREPARER):
Martin Narendorf (Martin Narendorf)

RESPONSIVE DOCUMENTS:
PUC06-03 Attachment 1.xls

		East to West	West to East	
MONTH		**SCHED_DELIVERED**	**SCHED_RECEIVED**	
Date		SPP --> ERCOT (MWh)	ERCOT --> SPP (MWh)	SUM
2018/1	Jan	49,041	48,300	97,341
2018/2	Feb	29,445	26,981	56,426
2018/3	Mar	31,171	15,142	46,313
2018/4	Apr	88,658	20,426	109,084
2018/5	May	157,929	5,606	163,535
2018/6	Jun	192,908	6,136	199,044
2018/7	Jul	252,721	10,611	263,332
2018/8	Aug	282,158	1,813	283,971
2018/9	Sep	174,963	5,639	180,602
2018/10	Oct	46,560	32,608	79,168
2018/11	Nov	24,896	26,396	51,292
2018/12	Dec	26,827	11,822	38,649


Welsh HVDC Schedule
MWH
300,000
250,000
200,000
150,000
100,000
50,000
0
ERCOT--> SPP
SPP --> ERCOT
Schedule Sum
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
2018

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PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-04

QUESTION:

For each month of the Test Year, please provide the peak demand on the Welsh DC tie when the direction of the energy flow was out from ERCOT.

ANSWER:

Please see response to PUC 6-03 for Welsh DC Tie energy flow information.

SPONSOR (PREPARER):
Martin Narendorf (Martin Narendorf)

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
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PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-05

QUESTION:

For each hour of the Test Year, please provide energy exports from ERCOT across the Welsh DC tie (in MWh or kWh).

ANSWER:

CenterPoint Houston does not have the requested information.

SPONSOR (PREPARER):
Martin Narendorf (Martin Narendorf)

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
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PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-06

QUESTION:

For each hour of the Test Year, please provide energy imports into ERCOT across the Welsh DC tie (in MWh or kWh).

ANSWER:

CenterPoint Houston does not have the requested information.

SPONSOR (PREPARER):
Martin Narendorf (Martin Narendorf)

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
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PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-07

QUESTION:

Please refer to workpaper "WP 11-F-Plant Functionalization.XLS," at worksheet "Acct 362 WP II-F 2N." Please comprehensively explain what assets are included in asset class E36201. Please also explain the difference between "sub 250" and "sub 260."

ANSWER:

Please refer to Exhibit DAW-1 CenterPoint Houston Depreciation Study 2017, Bates Stamp page 2503 for a comprehensive explanation of the assets included in asset class E36201. Sub 250 is for Station Equipment Assets and Sub 260 is for Main Power Equipment Assets.

SPONSOR (PREPARER):
Kristie Colvin/Dane Watson (Kristie Colvin/Dane Watson)

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
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PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-08

QUESTION:

Please refer to workpaper "WP II-F-Plant Functionalization.XLS," at worksheet "Acct 362 WP 11-F 2N." Please comprehensively explain what assets are included in asset class CE36201.

ANSWER:

Please refer to Exhibit DAW-1, Bates Stamp page 2503 for a comprehensive explanation of the assets included in asset class CE36201. CE36201 represents Completed Construction not Classified (FERC Account 106).

SPONSOR (PREPARER):
Kristie Colvin/Dane Watson (Kristie Colvin/Dane Watson)

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
2019 CEHE RATE CASE
DOCKET 49421-SOAH DOCKET NO. 473-19-3864

PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-09

QUESTION:

Please refer to workpaper "WP II-F-Plant Functionalization.XLS," at worksheet "Acct 362 WP II-F 2N." For each of the following distribution substations, please comprehensively explain the methodology the Company followed to assign more than 50% of the costs in asset class E36201 to the transmission function and attach the associated workpapers (separately as necessary for sub 250 and sub 260): System Spares, Baytown, East Bernard, Garden Villas, Magnolia Park, Tomball, Galena Park, Bellaire, Downtown, White Oak, University, Channelview, Jeannetta, Angleton, Gulf Chemical and Metallurgical, Bayway, Stewart, North Belt, Franklin, Gable Street, Fannin, Texas Instruments, and P.H. Robinson Plant.

ANSWER:

All the substations listed are functionalized using the same methodology. When a substation is first constructed, all its assets are assigned to distribution if its purpose is to serve distribution load or the assets are assigned to transmission if its purpose is to support transmission. Each asset (retirement unit) in each individual substation is reviewed by CenterPoint Engineering to determine whether it supports the transmission system, distribution system, or both. Transmission support is defined as equipment that operates at 69KV, 138Kv, or 345KV. Distribution support is defined as equipment that operates at 12KV or 35KV. Each asset is then assigned a percentage based on what function it supports. If the asset solely supports transmission, 100% of the asset is allocated to transmission. Examples of these assets are 138KV breakers, autotransformers or 345KV switches. If it solely supports distribution, 100% of the asset is allocated to distribution. Examples of these assets are power transformers, 12KV breakers, or 35KV switches. If an asset supports both the transmission and distribution systems, the asset is split between transmission and distribution based on its level of support of each system within each substation. Examples of these assets are SCADA sets, back-up battery systems, and ground mats. An overall percentage of transmission and distribution support for an individual substation is then calculated based on the allocations of its individual assets.

File titled "PUC06-09_2018_Substation_Allocations.xlsx" provides allocations by assets and substations.

The requested information is voluminous and will be provided to the propounding party only in electronic format on CD. Please contact Alice Hart at (713) 207-5322 to request a copy of the CD. Please see index of voluminous material below.

Date	Title	Preparer	Page #
Undated	E35301 (sfca 250)	Kristie Colvin / Martin Narendorf	1-152
Undated	E36201 (sfca 250)	Kristie Colvin / Martin Narendorf	153-598

SPONSOR (PREPARER):
Kristie Colvin / Martin Narendorf (Kristie Colvin / Martin Narendorf)

RESPONSIVE DOCUMENTS:
PUC06-09_2018_Substation_Allocations.xlsx

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
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PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-10

QUESTION:

Please refer to workpaper "WP II-F-Plant Functionalization.XLS," at worksheet "Acct 362 WP II-F 2N." For each of the following distribution substations, please explain the methodology the Company followed to assign more than 50% of the costs in asset class CE36201 to the transmission function: System Spares, Baytown, East Bernard, Garden Villas, Magnolia Park, Tomball, Galena Park, Bellaire, Downtown, White Oak, University, Channelview, Jeannetta, Angleton, Gulf Chemical and Metallurgical, Bayway, Stewart, North Belt, Franklin, Gable Street, Fannin, Texas Instruments, and P.H. Robinson Plant.

ANSWER:

The methodology used for all the listed substations is the same methodology described in the response to PUC06-09.

SPONSOR (PREPARER):
Kristie Colvin / Martin Narendorf (Kristie Colvin / Martin Narendorf)

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
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PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-11

QUESTION:

Please refer to workpaper "WP II-F-Plant Functionalization.XLS," at worksheet "Acct 362 WP II-F 2N." Please explain the differences in the methodology the Company follows to functionalize costs in asset classes E36201 versus CE36201. Please also include the difference in the methodology, if any, between assets designed as "sub 250" versus "sub 260."

ANSWER:

There is no difference in the methodology used to functionalize costs in asset classes E36201 and CE36201 or assets designated as sub 250 and sub 260.

SPONSOR (PREPARER):
Kristie Colvin / Martin Narendorf (Kristie Colvin / Martin Narendorf)

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
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PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-12

QUESTION:

For each of the following distribution substations, please identify if the costs in account 36201, station equipment, which the Company has directly assigned 100% to the transmission function, are exclusively associated with serving retail customers. Winfree Substation, Camden Substation, Celanese Chemical Substation, Lomax Substation, Diamond Shamrock Battleground Rd. Substation, Tidal Road Substation, Dow Chemical Co Freeport Substation, ARCO Polymers, Inc.-Monument Substation, Soltex Substation, Himont Substation, City of Houston-Clinton Drive Substation, Colonial Pipeline Substation, Anheiser Substation, Monsanto Substation, Champion International-Sheldon Substation, Texas Petrochemicals Cogen Substation, Barnes Substation, Tenneco Substation, Enterprise Products Substation, General Foods Substation, FMC Substation, AMOCO-Chocolate Bayou Substation, Cameron Iron-Hempstead Substation, ARCO _Chemical-Bayport Substation, Rohm & Haas Substation, U. S. Steel Substation, Shell-Deer Park Substation, ARCO Refinery Substation, ARCO Chemical Substation, Upjohn Substation, Chevron Chemical Substation, Dow-Velasco Substation, City of Houston-Lynchberg Pump Substation, Big 3 Industries-Channelview Substation, Big 3 Industries-Freeport Substation, Ethyl Substation, ARCO Chemical-South Substation, Drilco Substation, Exxon-Baytown Substation, Big 3 Industries-Bayport Substation, DuPont-Deer Park Substation, American Hoechst Substation, Crown Central Petroleum Substation, Exxon-Hatcherville Substation, Phillips Chemicals Substation, A. B. Chemicals Substation, NASA/Johnson Space Center Substation, USS Chemicals-Novamont Substation, Union Carbide-LaPorte Substation, Rollins Substation, Mula Substation, Franklin's Camp Substation, Brown and Root Substation, Bryan Substation, Exter Substation, Foster Substation, Texas Substation, Texwal Substation, US Gypsum Substation, Explorer Pipeline Substation, Seaway Substation, Cougar Substation, Deepwater Plant Substation.

ANSWER:

All costs in account 36201 that are directly assigned 100% to the transmission functions for the listed substations are associated with serving retail customers as well as providing protection and monitoring of the CenterPoint Houston system. These costs also include equipment for the metering of the retail customer. CenterPoint Houston assigned the 100% transmission functionalization based on the methodology used in Docket No. 38339 that is applied to all the substations on our system whether customer owned or CenterPoint Houston owned. Since these substations are connected to the transmission system at 69KV and above voltage levels, they are classified as transmission substations.
Note that the Deepwater Plant substation listed is a CenterPoint Houston owned substation, not a retail customer substation.

SPONSOR (PREPARER):
Kristie Colvin / Martin Narendorf (Kristie Colvin / Martin Narendorf)

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
2019 CEHE RATE CASE
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PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-13

QUESTION:

Does the Company believe that costs of its assets on the system that are functionalized to transmission but are exclusively involved in providing service to retail delivery customers are wholesale transmission costs properly included in its TCOS? Why or why not?

ANSWER:

As explained in the response to PUC06-12, the costs of our assets involved in providing service to retail delivery customers are to provide metering of the retail customer, as well as protection and monitoring of the CenterPoint Houston system. Response to PUC06-12 also explains that these costs are functionalized to transmission using the same methodology used in Docket No. 38339 that is also applied to CenterPoint Houston's substations and are properly included in our TCOS filings.

SPONSOR (PREPARER):
Kristie Colvin / Martin Narendorf (Kristie Colvin / Martin Narendorf)

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
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PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-14

QUESTION:

Please refer to workpaper "WP II-F-Plant Functionalization.XLS," at worksheet "Acct 362 WP II-F 2N." Please explain why the entry for System Spares Substation, asset class E36201, sub 260, is so out of proportion as compared with the other entries in this workpaper. What is going on at this substation that differentiates it from other substations and why are more than half the costs assigned to the transmission function?

ANSWER:

The entry in worksheet "Acct 362 WP II-F 2N" in workpaper "WP II-F-Plant Functionalization.XLS" titled "System Spares Substation" is not a substation but is the location that the Company designates for its spare major equipment including autotransformers, power transformers, mobile substations, and transmission class (>69KV) breakers. This equipment is kept on hand to provide the ability to replace failed major equipment that has long lead times. These assets are functionalized by reviewing the items and assigning the equipment as follows:

Autotransformers – Functionalized to transmission
Power Transformers – Functionalized to distribution
Transmission Class Breakers – Functionalized to transmission
Mobile Substations – Functionalized to distribution

The reason that more than half of these costs in FERC 362 are assigned to the transmission function is that the autotransformers described above are typically more expensive than power transformers. In addition, the inclusion of transmission class breakers described above contributes to the transmission function.

SPONSOR (PREPARER):
Kristie Colvin / Martin Narendorf (Kristie Colvin / Martin Narendorf)

RESPONSIVE DOCUMENTS:
None

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PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-15

QUESTION:

With respect to the Company's proposed weather normalization of energy, please state whether the historical energy data used in the Company's weather normalization modeling were adjusted to reflect customer annualizations, customer migrations, annualization of the effects of energy-efficiency measures that were in effect during only part of the year, and all other adjustments that have been proposed by the Company in this case with respect to Test Year energy. For each adjustment not reflected in the Company's weather normalization modeling, please explain why that adjustment was not performed for that purpose.

ANSWER:

The weather adjustment models are estimated using actual sales and demand data for the historical estimation period.
Energy models are estimated using actual daily usage divided by the number of customers as the variable to be explained.
Daily weather adjustments from these models are multiplied by the actual number of customers to determine the daily weather adjustment.
These daily adjustments are added up to the monthly level to get the calendar month and billing month weather adjustments.
Then actual historical monthly sales are adjusted for weather, energy efficiency impacts during the test year, and customer growth.
The customer growth adjustment occurs last, and scales all months to represent what adjusted sales would be at the December 2018 customer level.
Annual adjustments are shown in H-1.1 and monthly adjustments are shown in H-1.2.
The mechanics of the customer growth adjustments are shown in working paper exhibit WP H-1.2.
The customer adjustment is applied last, and this means that actual monthly sales, monthly weather adjustments and monthly energy efficiency adjustments are all scaled by the same monthly proportions.
No adjustments were made for customer migration because there were no significant rate class changes in 2018. The only customer adjustment is the one that is applied to scale monthly sales, weather adjustments and energy efficiency adjustments to December 2018 customer levels.

SPONSOR (PREPARER):
Stuart McMenamin (Stuart McMenamin)

RESPONSIVE DOCUMENTS:
None

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PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-16

QUESTION:

Please quantify the effect on the Company's requested overall revenues if Test Year amounts were not rounded to thousands in the Company's cost study. Please explain the methodology the Company followed to round its TY amounts to thousands.

ANSWER:

No analysis has been performed to quantify the effect on CenterPoint Houston's requested overall revenues if Test Year amounts were not rounded to thousands. Test year amounts were divided by $1,000, then rounded to the nearest dollar using Microsoft round function. To facilitate tie outs between worksheets and schedules, Microsoft roundup and rounddown functions were also used.

SPONSOR (PREPARER):
Kristie Colvin (Kristie Colvin)

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
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PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-17

QUESTION:

Please explain what the functionalization factor, "Misc Intangible Plant - NMF S/W," abbreviation "E30302," represents, where the functionalization data comes from, and how this functionalization factor was developed.

ANSWER:

"Misc Intangible Plant – NMF S/W" abbreviation "E30302" represents Miscellaneous Intangible Plant Non Mainframe Software. E30302 is the Asset Class where the costs of these assets reside in the SAP Asset Module. The functionalization data comes from the SAP Asset Module and the costs were functionalized based on direct assignment of each asset. This functionalization can be found in "WP II-F-Plant Functionalization.xlsx" tab "Acct 303 WP II-F-2A".

SPONSOR (PREPARER):
Kristie Colvin (Kristie Colvin)

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
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PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-18

QUESTION:

How did the Company develop the allocation data for the functionalization factor "E39702," Computer Equipment? Please explain and provide the associated workpapers supporting the development of this functionalization factor.

ANSWER:

The methodology by which the Company developed the allocation data for the functionalization factor "E39702 Computer Equipment" can be found in "WP II-F-Plant Functionalization.xlsx" tabs "Summary WP II-F-2", "Acct 39702 worksheet WP II-F-2AK", and "Acct 39702 WP II-F-2AL". Please refer to Dane Watson's testimony, Bates Stamp Page 2529 which describes the assets in Account 397.02 as printers, laptops and servers which are used by employees. Therefore, the entire costs are allocated based on the number of employees and none are directly assigned. Due to the volume, computer equipment is treated as mass property and is not directly assigned to individuals.

SPONSOR (PREPARER):
Kristie Colvin/Dane Watson

RESPONSIVE DOCUMENTS:
None

PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-19

QUESTION:

In the Company's cost study, a portion of plant recorded in certain transmission-related FERC accounts is functionalized to distribution, and a portion of plant recorded in certain distribution-related FERC accounts is functionalized to transmission. Why are transmission O&M expense FERC accounts and distribution O&M expense FERC accounts not also functionalized to some degree among transmission and distribution, following the functionalization of plant?

ANSWER:

Certain distribution and transmission expense FERC accounts are functionalized among transmission and distribution similar to how plant in certain distribution and transmission FERC accounts is functionalized among transmission and distribution. FERC accounts 5690 and 5700 are functionalized based on the overall plant functionalization percentages in FERC account E353 for transmission and distribution. FERC accounts 5910 and 5920 are functionalized based on the overall plant functionalization percentages in FERC account E362 for transmission and distribution. See response to PUC06-09 for methodology used to functionalize FERC accounts E353 and E362.

SPONSOR (PREPARER):
Kristie Colvin / Randal Pryor / Martin Narendorf (Kristie Colvin / Randal Pryor / Martin Narendorf)

RESPONSIVE DOCUMENTS:
None

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PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-20

QUESTION:

For the project listed under Project Number HLP/00/0899 and described in the WP RMP-2 Capital Project List Summaries (years 2013-2015): "This project is needed to reduce the level of induced voltage onto the BNSF railroad for the safety of BNSF personnel and the public. The induced voltage either exceeds or has the capability of exceeding 50V at each railroad insulated joint location" (and also found in the 'WP RMP-2 Capital Project List Detail' spreadsheets for these years):

a. When was the line associated with this project placed into service?

b. What dollar amount, if any, was incurred during the rebuilding, reconductoring,or upgrading of existing electric facilities?

c. How did CenterPoint become aware of the need for this mitigation work? Did BNSF or another third party request this work?

d. Why does CenterPoint believe this work should be capitalized instead of treated as an operations or maintenance expense?

ANSWER:

For the project listed under Project Number HLP/00/0899 and described in the WP RMP-2 Capital Project List Summaries (years 2013-2015) which was needed to reduce the level of induced voltage onto the BNSF railroad, see following responses.

a. The 345kV Ckt 74C was installed in 1983 per the Transmission Statistical Book.
b. The cost to install the mitigation for 345kV Ckt 74C was $14,123,846.41. Work Order #79292517 is still open and appears to be the difference between this cost and what was listed in WP RMP-2, which is $13,857,331.
c. CEHE was made aware of the need for this mitigation after a complaint was received from BNSF. The mitigation work was agreed upon by CEHE and BNSF in accordance with the attached Mitigation Report prepared by Electrical Interference Solutions, Inc. See attachment PUC06-20 Mitigation Report Attachment 1.pdf.
d. This work should be capitalized because the project involved a twelve-mile installation of 636MCM ASCR on transmission structures as an aerial shield (i.e. counterpoise), as well as two twelve-mile installations of parallel 500 MCM copper shielded cable buried on each side of the transmission corridor.

SPONSOR (PREPARER):
Randal Pryor/Martin Narendorf (Randal Pryor/Martin Narendorf)

RESPONSIVE DOCUMENTS:
PUC06-20 Mitigation Report Attachment 1.pdf

10/21/2012

Induced Voltages Between CNP and BNSF

Phase II: Physical Mitigation Design

Electrical Interference Solutions, Inc.

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ORGANIZATION(S) THAT PREPARED THIS DOCUMENT

EISI
Corr Comp, Inc.

Induced Voltages Between CNP and BNSF

Phase II: Physical Mitigation Design

Contents

Executive Summary

This report provides to CenterPoint Energy (CNP) detailed physical mitigation options in the ongoing study of magnetically induced 60 Hz steady-state ac voltage in excess of 50 V rms on the track of the Burlington Northern Santa Fe Railroad (BNSF). Electrical Interference Solutions, Inc. (EISI) was retained to evaluate the issues and design physical mitigation to address the existing steady-state issues, as well as potential fault induced conditions. Because Corr Comp, Inc. had previously modeled this right-of-way under a prior contract, they were brought on-board to use the proven computer model to design and evaluate mitigation options.

The study is based on the existing physical configurations of the power lines and railroad tracks, estimated current data provided by CenterPoint for steady-state and fault conditions, and measured load and phase unbalance data. Using these data, worst-case conditions were modeled and the resulting induces voltages were compared against acceptance criteria agreed upon by the railroad and the power company.

Three mitigation package options were developed (A, B, and C). Each of the options meets all the design criteria for steady-state and fault induction, including stopped-train conditions. The mitigation package options were presented to CNP and BNSF at a design review meeting on December 6, 2011.

Option C was agreed upon by CNP and BNSF as the option to be implemented.

While Option C requires less mitigation to be installed, it does require post-installation testing and computer modeling to insure effective mitigation under worst-case conditions. While we are confident that the installed mitigation will be sufficient, there is a possibility that some of the differed mitigation will need to be installed after testing and evaluation.

After the design review, various construction considerations resulted in changes to the extent and alignment of the shield wires. While these changes appear to have only minor impact on induced voltages, the post-installation testing and evaluation is necessary to insure acceptable results under all expected conditions.

The selected mitigation includes:

- Transpose two phase wires in circuit 74C
- Install an aerial shield wire next to transmission line for about 12 miles
    - 636MCM ACSR conductor
    - On the transmission structures, 57 feet west, and 62 feet west of transmission centerline
    - With 5 ohm grounds at each structure
- Two buried 500MCM copper shield wires, buried together, east of the track
    - Each about 12 miles long
- Two buried 500MCM copper shield wires, buried together, west of the track
    - Each about 12 miles long

Introduction and Background

CenterPoint Energy operates a double circuit 345-kV transmission line (circuits 74C and 75B) north of Houston that parallels the Burlington Northern Santa Fe Railroad (BNSF) for approximately 15 miles. Figure 1 below shows an overhead map of the exposure region. Previous field testing and analysis showed that the railroad is experiencing elevated steady-state 60 Hz voltage in the parallel exposure, from approximately MP 89.0 to MP 103.5. Electrical Interference Solutions, Inc. (EISI) was retained to evaluate the issues and design physical mitigation to address the existing steady-state issues, as well as potential fault induced conditions. Because Corr Comp, Inc. had previously modeled this right-of-way under a prior contract, they were brought on-board to use their proven computer model to design and evaluate mitigation options.

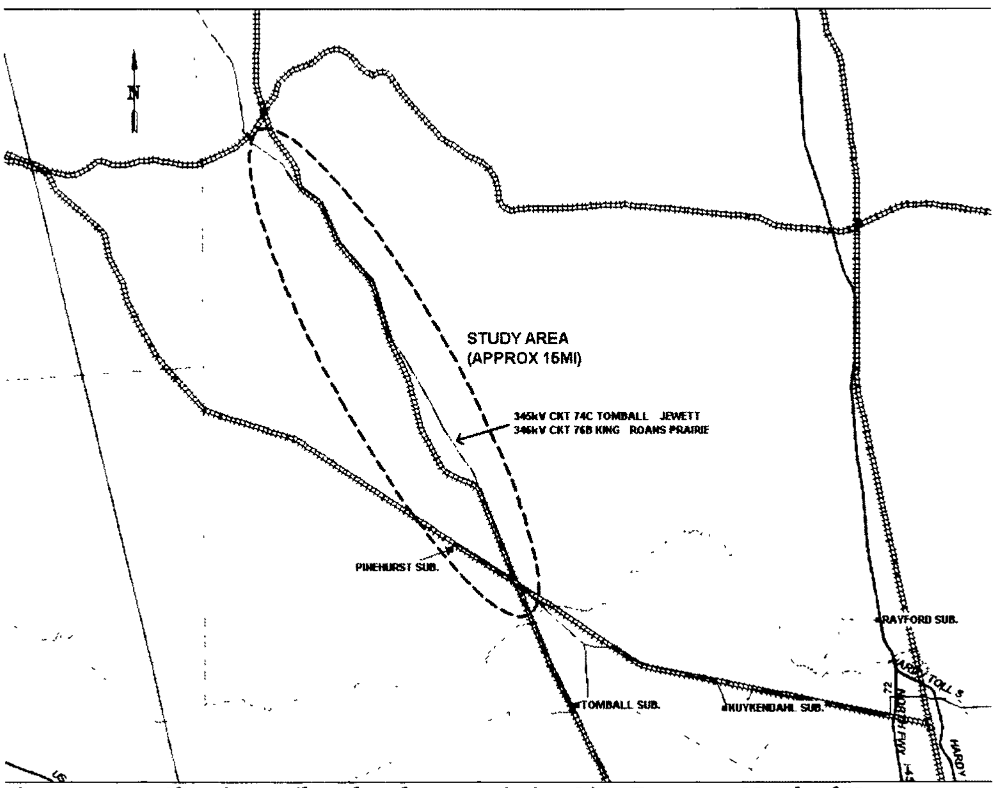

Figure 1. Map Showing Railroad and Transmission Line Exposure North of Houston.

POWER SYSTEM PARAMETERS

The purpose of this study is to mitigate the predicted induced voltage caused by the worst-case conditions including emergency load transmission line currents of the 345-kV transmission line for the BNSF railroad that is within the exposure region. CenterPoint has provided specific information on the transmission line. Relevant information includes (all AC voltage and current values in this report are rms):

- The 3-phase line-to-line voltage for both circuits (74C and 75B) of the transmission line is 345 kV.
- The transmission line phase sequence in time is CBA.
- Steel power structures with nominal 1000-ft spacing.

- Phase conductors are a two-conductor bundled Falcon ACSR.
- Overhead shield wires are 3/8" diameter HS steel conductor.
- Overhead shield wires are multi-grounded to the transmission line towers.
- Delta phase arrangement for most of the exposure. South end of exposure is a vertical phase arrangement.
- The transmission line runs roughly in a north-south direction. For clarity, direction on the transmission line will be referred to simply as north or south.
- The emergency load steady-state transmission line current for circuit 74C is 3.672 kA or 2194 MVA (this value has been used in the analysis).
- The emergency load steady-state transmission line current for circuit 75B is 2.862 kA or 1710 MVA (this value has been used in the analysis).
- Unbalance (residual current) for the power circuit is estimated to be 7.2% (2.4% zero sequence current).
- Power flow for circuit 74C is from Singleton to Tomball Substation
- Power flow for circuit 75B is from Roans Prairie to Kuykendahl
- Transmission structure footing resistances are assumed to be 5 ohms.
- The single line to ground fault currents for circuit 74C of the 345-kV line along the exposure are:
  - Near Tomball: 12257 A (7715 A from Tomball, 4661 A from Singleton).
  - At 10% line exposure from Tomball: 11940 A (7287 A from Tomball, 4775 A from Singleton).
  - At 20% line exposure from Tomball: 11677 A (6903 A from Tomball, 4898 A from Singleton).
  - At 30% line exposure from Tomball: 11463 A (6557 A from Tomball, 5031 A from Singleton).
  - At 40% line exposure from Tomball: 11292 A (6243 A from Tomball, 5175 A from Singleton).
  - At 50% line exposure from Tomball: 11161 A (5957 A from Tomball, 5331 A from Singleton).
  - At 60% line exposure from Tomball: 11067 A (5696 A from Tomball, 5500 A from Singleton).
  - At 70% line exposure from Tomball: 11008 A (5456 A from Tomball, 5682 A from Singleton).
  - At 80% line exposure from Tomball: 10984 A (5235 A from Tomball, 5880 A from Singleton).
  - At 90% line exposure from Tomball: 10994 A (5031 A from Tomball, 6095 A from Singleton).
  - Near Singleton: 11038 A (4842 A from Tomball, 6329 A from Singleton).
- The single line to ground fault currents for circuit 75B of the 345-kV line along the exposure are:
  - Near Kuykendahl: 9410 A (4785 A from Kuykendahl, 4671 A from Roans Prairie).
  - At 10% line exposure from Kuykendahl: 9404 A (4629 A from Kuykendahl, 4822 A from Roans Prairie).
  - At 20% line exposure from Kuykendahl: 9420 A (4483 A from Kuykendahl, 4983 A from Roans Prairie).
  - At 30% line exposure from Kuykendahl: 9455 A (4346 A from Kuykendahl, 5156 A from Roans Prairie).
  - At 40% line exposure from Kuykendahl: 9513 A (4218 A from Kuykendahl, 5341 A from Roans Prairie).
  - At 50% line exposure from Kuykendahl: 9592 A (4097 A from Kuykendahl, 5541 A from Roans Prairie).
  - At 60% line exposure from Kuykendahl: 9695 A (3983 A from Kuykendahl, 5758 A from Roans Prairie).
  - At 70% line exposure from Kuykendahl: 9822 A (3876 A from Kuykendahl, 5992 A from Roans Prairie).
  - At 80% line exposure from Kuykendahl: 9976 A (3775 A from Kuykendahl, 6247 A from Roans Prairie).
  - At 90% line exposure from Kuykendahl: 10158 A (3679 A from Kuykendahl, 6525 A from Roans Prairie).

- Near Roans Prairie: 10372 A (3589 A from Kuykendahl, 6829 A from Roans Prairie).
- 4-cycle fault clearing time for communication aided relaying scheme (this clearing time has been used for this analysis).
- 4 to 48-cycle fault clearing time for non-communication aided relaying scheme (this clearing time has not been used for this analysis).
- Circuit 74C reclosure sequence: Singleton end – 1 second hot-bus to hot-or-dead-line and 21 seconds hot-bus to dead-line. Tomball end - 16 seconds hot-bus to hot-or-dead-line and 31 seconds hot-bus to hot-line.
- Circuit 75B reclosure sequence: Roans Prairie end - 1 second hot-bus to hot-or-dead-line and 20 seconds hot-bus to dead-line. King end - 7 seconds hot-bus to hot-or-dead-line and 27 seconds hot-bus to hot-line.
- Soil resistivity has been assumed to be 18.2 ohm·m.
- The fault-condition safety touch potential limit for a 110-lb person, calculated using IEEE Std. 80 procedures with the above 4-cycle clearing time, is 462 V.

RAILROAD SYSTEM PARAMETERS

The BNSF have also provided information on the track signal system. Important railroad and signal system information includes:

- One BNSF signaled main track at the center of the ROW in the nominally parallel portion of the exposure.
- Continuously-welded rails.
- Train Control by block signaling, using ElectroCode units at track insulated joints.
- Several at-grade crossings within the exposure region are controlled by signal systems using GCP's and HXP's.
- Narrow band shunts are used in the exposure at crossing signal operating frequencies.
- Two insulated joint locations have tuned joint couplers installed.
- Signal diagrams were provided showing the locations and operating frequencies of equipment such as insulated joints, signals, crossings, switches and sidings, etc.

STEADY-STATE CONDITION (PERSONNEL SAFETY)

This section of the report considers the steady-state magnetic-field induction from the double circuit 345-kV transmission line circuit to the BNSF tracks from the perspective of personnel safety. The steady-state emergency load currents of 3.672 kA and 2.862 kA have been used in the analysis for circuits 74C and 75B respectively. A diagram of the existing power configuration is shown in Figure 2. The rail-to-ground personnel safety voltage limit under consideration by the U.S. railroad community is 25 V[1]. The Canadian Standards Association (CSA) also recommends this rail-to-ground voltage level for personnel safety. They recommend 50 V for longitudinally induced voltages in railway signaling and communications circuits, under normal power line conditions. For track circuits, they include the special note, "For adjacent track sections of equal length separated by a pair of IJ's, the ac voltage developed across each insulated rail joint is twice the maximum voltage of each rail with respect to remote earth. To limit the voltage across insulated rail joints to 50 V, the maximum rail-to-remote earth voltage should not exceed 25 V."[2] However, the voltage on one side of the insulated joint may be less than 25 V, so the sum of the voltages on both sides of the insulated joint is compared that with the 50-V safety limit.

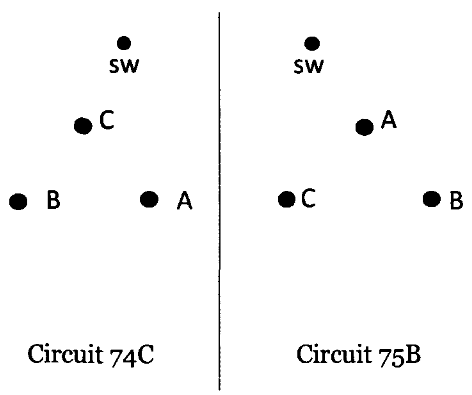

Figure 2. Existing Phasing Arrangement for the two CNP Circuits (Looking North in Exposure Region)

CenterPoint has provided the steady-state emergency load currents listed above for the double circuit 345-kV transmission line. The worst-case condition is with both circuits energized. However, both single circuit cases have also been analyzed for completeness.

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[1] M. Frazier, E. Logan, and B. Cramer, *'Blue Book' on Inductive Coordination Task Force Progress Report*, AREMA Annual Conference, Chicago, Illinois, September 2001.
[2] *Electrical Coordination, Canadian Electrical Code, Part III*, Canadian Standards Association (CSA), C22.3 No. 3-98, August 1998.

NORMAL TRACK CONDITIONS

Figures 3, 4, and 5 show the predicted steady-state rail to ground voltage profile for high track ballast resistivity (100 ohm-kft) and three power load cases respectively: both circuits energized, only circuit 74C energized, and only circuit 75B energized. Calculated voltages are plotted in these figures vs. approximate railroad milepost. The emergency load currents for each circuit is assumed, and the worst-case sum of the induced rail voltage for balanced and unbalanced transmission-line current was used to develop the plots in Figures 3, 4, and 5 (7.2% residual current in each circuit has been assumed as provided by CenterPoint). Also, for this analysis no mitigation measures have been modeled. Each figure includes the location of street crossings. This is done to help the reader relate the induced voltages with a specific location.

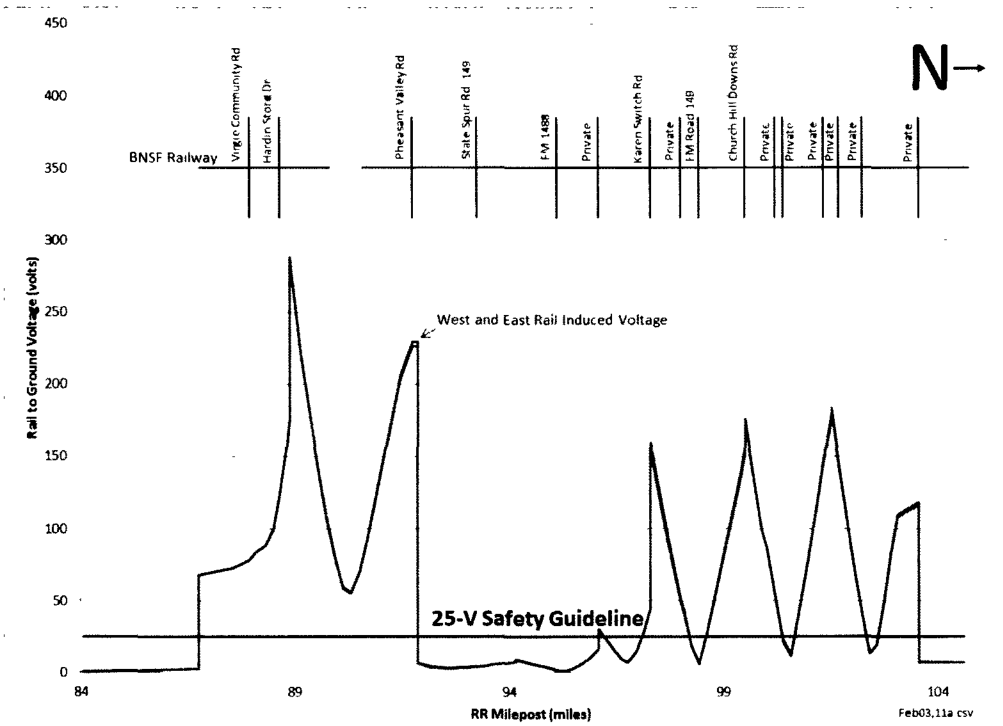

Figure 3. Predicted Steady-State Rail to Ground Voltage for Circuits 74C and 75B Energized.

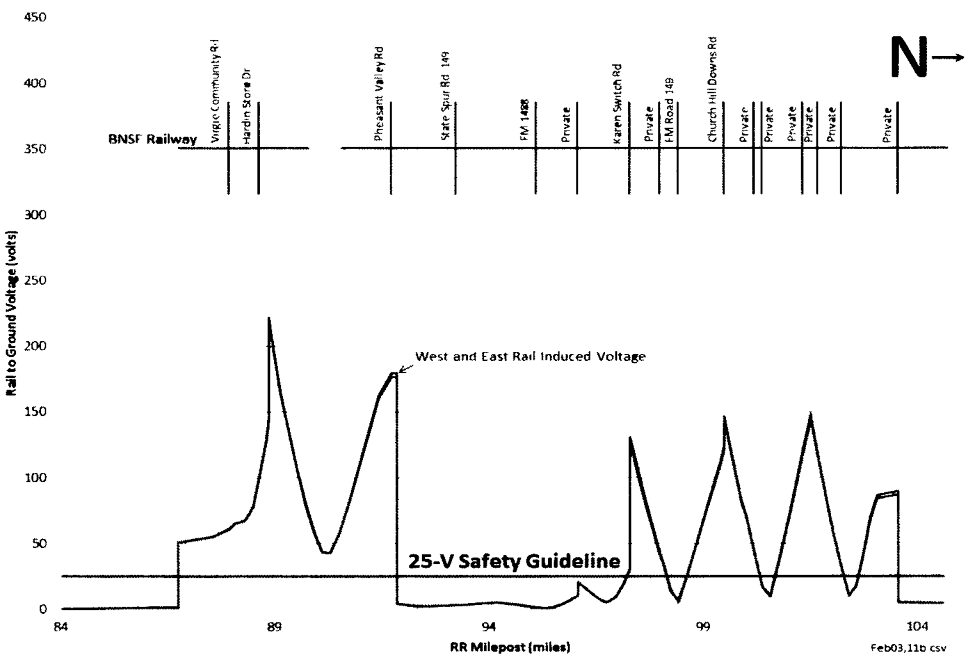

Figure 4. Predicted Steady-State Rail to Ground Voltage for Circuit 74C Energized and 75B Out of Service.

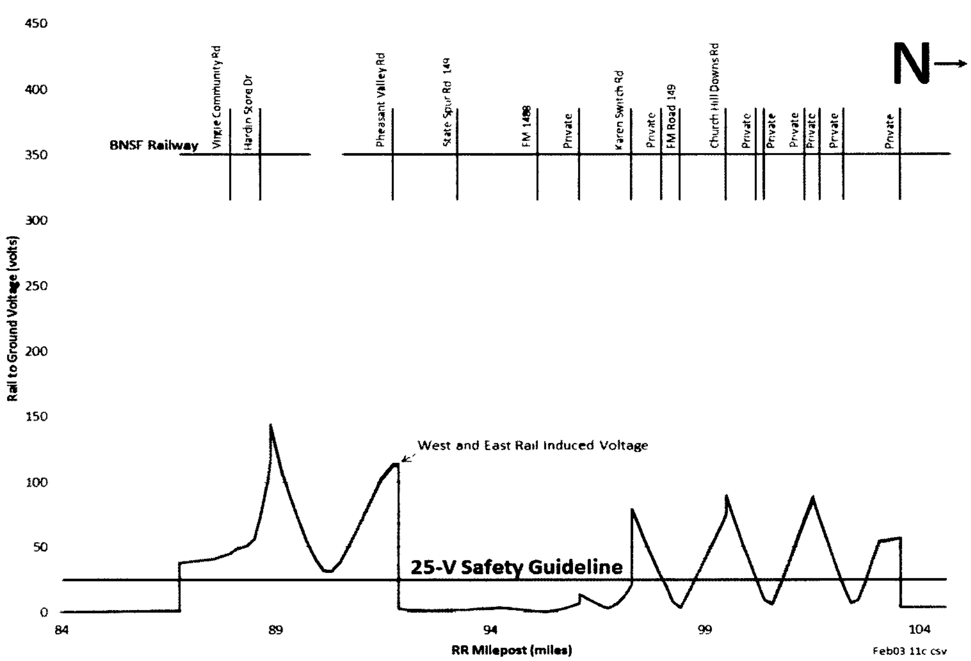

Figure 5. Predicted Steady-State Rail to Ground Voltage for Circuit 75B Energized and 74C Out of Service.

From Figures 3, 4, and 5 it can be seen that all of the rail to ground voltage profiles significantly exceed the 25- rail-soil and the 50-V accessible safety touch potential guideline at multiple locations. Specifically, in Figure 3 it can be seen that the maximum predicted rail to ground voltage is 289 V, which is the worst of all three figures. Thus, the "both circuits energized" case will be the focus of mitigation throughout this report.

A relatively high ballast resistivity (100 ohm-kft) was assumed for these analyses because that condition tends to result in higher rail-induced voltage. High values of ballast resistivity can occur during hot-dry periods and during cold periods when the ballast is frozen.

Figure 6 shows a bar graph of the predicted voltage across the insulated joints throughout the exposure region for the worst-case of both circuits energized. The bar graph shows that at one insulated joint location a voltage of 466 V is predicted. This suggests that a reduction of approximately 90% of that predicted voltage is necessary to reduce that accessible voltage to below the 50-V guideline.

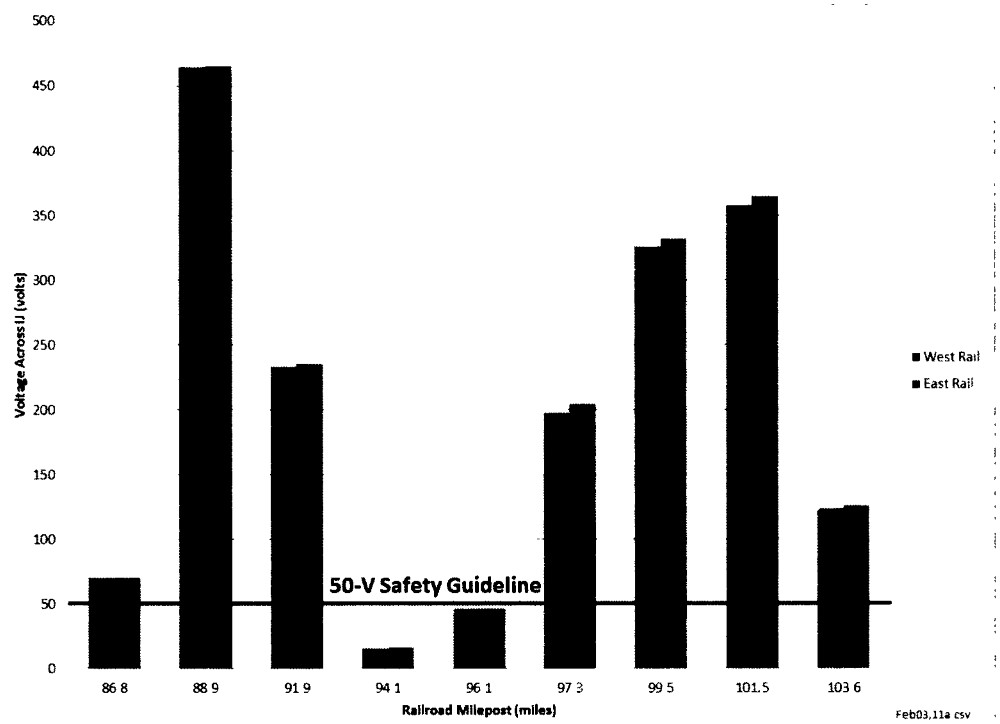

Figure 6. Predicted Steady-State Voltage Across Insulated Joints for Circuits 74C and 75B Energized.

RECOMMENDED MITIGATION MEASURES

Three mitigation alternatives have been investigated, and all are predicted to provide sufficient reduction of induced track voltage given the specific assumptions for each alternative. The same worst-case assumptions described in Section 2.1 above have been used in this mitigation analysis. The mitigation alternatives are outlined below as Mitigation Alternatives A, B, and C.

Mitigation Alternative A

The components of Mitigation Alternative A are listed as follows.

1. A phase change in circuit 74C. The A and B phases switch location as shown in Figure 7 below. The left configuration is the existing configuration, and the right configuration is the arrangement recommended. The analysis results that provide the basis for the recommended phase configuration change is shown in Appendix A.

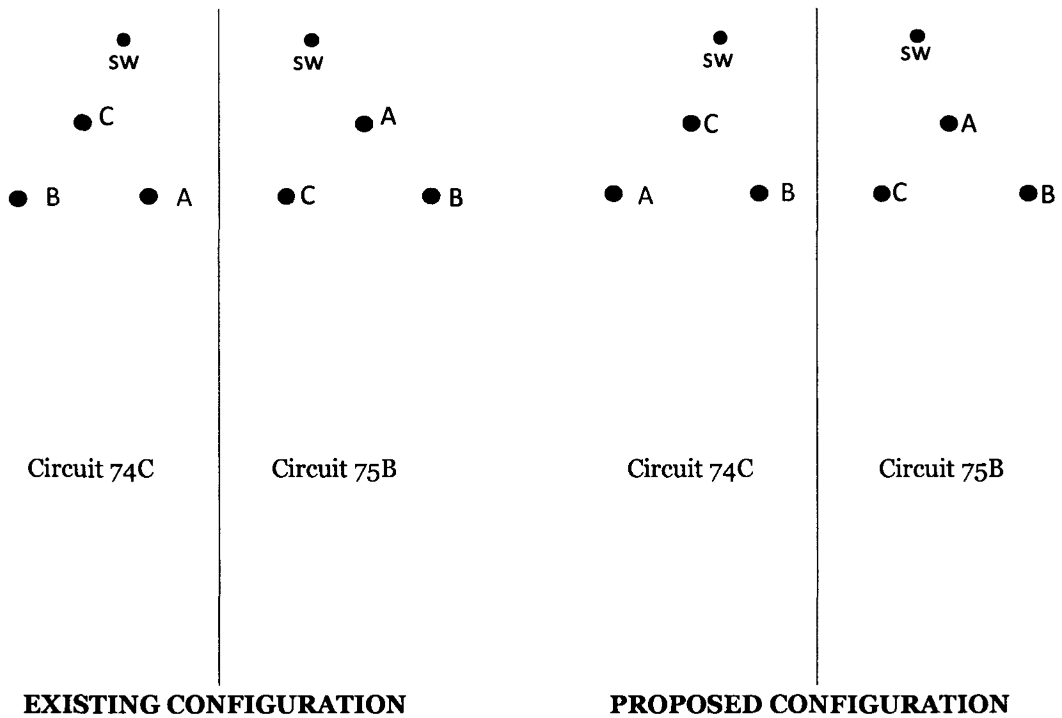

Figure 7. Phasing Arrangements for the two CNP Circuits (Looking North in Exposure Region).

2. One 636 MCM Rook ACSR aerial conductor extending from tower 18493 to tower 2396. It is recommended that the conductor be:
    - strung on separate poles that run parallel to the power line,
    - 57 feet west of the centerline of the power towers
    - electrically continuous from tower 18493 to tower 2396,
    - strung 10 ft. vertically below the mean height of the lowest phase conductor for the condition of greatest phase-conductor sag,
    - and electrically-grounded at all poles with a 5-ohm impedance to ground.

3. One 4/0 bare buried copper conductor extending from one mile south of the railroad insulated joints at approximate railroad MP 88.9 to the insulated joints located at 103.58. It is recommended that the counterpoise be
    - 12.5 ft. east of the BNSF track centerline,
    - parallel to the BNSF track,

- be buried 6 ft. below the track or 4-ft below grade,
- and electrically continuous throughout.

4. One 4/0 bare buried copper conductor extending from one mile south of the railroad insulated joints at approximate railroad MP 88.9 to the insulated joints located at 103.58. It is recommended that the counterpoise be
   - 17.5 ft. east of the BNSF track centerline,
   - parallel to the BNSF track,
   - be buried 6 ft. below the track or 4-ft below grade,
   - and electrically continuous throughout.

5. One 4/0 bare buried copper conductor extending from one mile south of the railroad insulated joints at approximate railroad MP 88.9 to the insulated joints located at 103.58. It is recommended that the counterpoise be
   - 12.5 ft. west of the BNSF track centerline,
   - parallel to the BNSF track,
   - be buried 6 ft. below the track or 4-ft below grade,
   - and electrically continuous throughout.

6. One 4/0 bare buried copper conductor extending from 3000 ft. south of the railroad insulated joints at approximate railroad MP 88.9 to 200 ft. north of the insulated joints located at 91.9. It is recommended that the counterpoise be
   - 17.5 ft. west of the BNSF track centerline,
   - parallel to the BNSF track,
   - be buried 6 ft. below the track or 4-ft below grade,
   - and electrically continuous throughout.

7. Two added insulated joint locations at railroad MP 90.3 and 100.6.

Modeling of Mitigation Alternative A results in significant reduction of predicted induced rail to ground voltage for the "both circuits energized" case as is shown in Figure 8. The figure shows profiles of the maximum induced voltage of both rails and key road crossings as well. Figure 9 shows the voltage across the insulated joints which would be the maximum predicted accessible voltage.

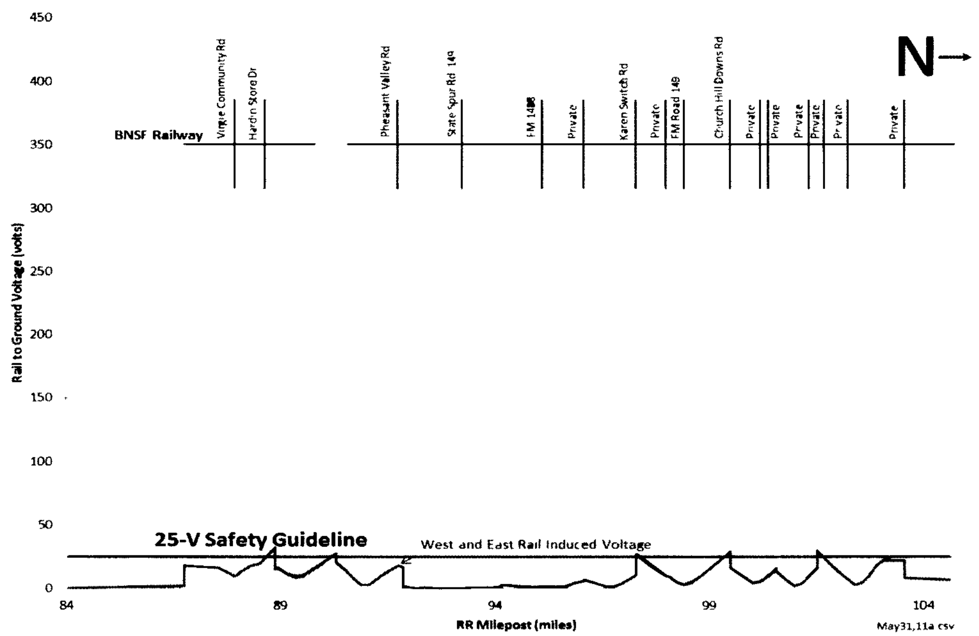

Figure 8. Predicted Steady-State Rail to Ground Voltage for Circuits 74C and 75B Energized with Mitigation Alternative A Modeled.

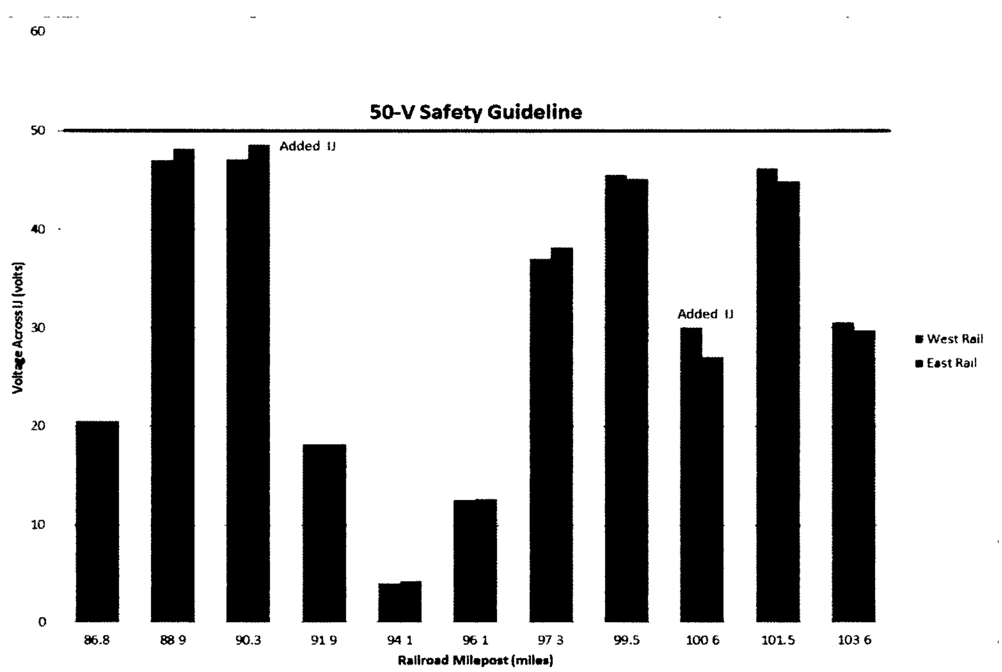

Figure 9. Predicted Steady-State Voltage Across Insulated Joints for Circuits 74C and 75B Energized with Mitigation Alternative A Modeled.

The maximum predicted accessible voltage across an insulated joint shown in Figure 9 is 48.7 V which is below the 50-V safety guideline. Thus, this mitigation alternative is a viable option. However, there is concern that a separate trench would have to be dug for each of the four buried conductors and therefore has investigated a modification of Mitigation Alternative A that may be more cost effective.

Mitigation Alternative B

The primary reason for considering Mitigation Alternative B is to reduce cost from that of Alternative A. The cost reduction would come from burying two conductors in each trench instead of one, and the conductors would be spaced vertically one foot apart. However, the conductor size of all four conductors would have to increase to 500 MCM bare copper conductors in order to obtain the required effectiveness of the mitigation conductors. Mitigative effectiveness of the buried conductors is in essence lessened as the conductors are brought closer together, and this is the reason for the increase in conductor size recommended.

The components of Mitigation Alternative B are listed as follows.

1. Same phase configuration change as indicated in #1 of Mitigation Alternative A.

2. Same aerial conductor and specifications as indicated in #2 of Mitigation Alternative A.

3. Trench 1: One 500 MCM bare buried copper conductor extending from one mile south of the railroad insulated joints at approximate railroad MP 88.9 to the insulated joints located at 103.58. It is recommended that the counterpoise be
   - 12.5 ft. east of the BNSF track centerline,
   - parallel to the BNSF track,
   - be buried 6 ft. below the track or 4-ft below grade,
   - and electrically continuous throughout.

4. Trench 1: One 500 MCM bare buried copper conductor extending from one mile south of the railroad insulated joints at approximate railroad MP 88.9 to the insulated joints located at 103.58. It is recommended that the counterpoise be
   - 12.5 ft. east of the BNSF track centerline,
   - parallel to the BNSF track,
   - be buried 5 ft. below the track or 3-ft below grade,
   - and electrically continuous throughout.

5. Trench 2: One 500 MCM bare buried copper conductor extending from one mile south of the railroad insulated joints at approximate railroad MP 88.9 to the insulated joints located at 103.58. It is recommended that the counterpoise be
   - 12.5 ft. west of the BNSF track centerline,
   - parallel to the BNSF track,
   - be buried 6 ft. below the track or 4-ft below grade,
   - and electrically continuous throughout.

6. Trench 2: One 500 MCM bare buried copper conductor extending from 3000 ft. south of the railroad insulated joints at approximate railroad MP 88.9 to 200 ft. north of the insulated joints located at 91.9. It is recommended that the counterpoise be
   - 12.5 ft. west of the BNSF track centerline,
   - parallel to the BNSF track,
   - be buried 5 ft. below the track or 3-ft below grade,
   - and electrically continuous throughout.

7. Same addition of two insulated joint locations at railroad MP 90.3 and 100.6 as indicated in #7 of Mitigation Alternative A.

Figure 10 shows the predicted induced voltage from modeling Mitigation Alternative B. The figure is set up similar to Figure 8. The predicted accessible voltage across the insulated joints is shown in Figure 11. The maximum predicted accessible voltage is 49.3 V which is less than the 50-V safety guideline. Thus, this mitigation alternative is also a viable option.

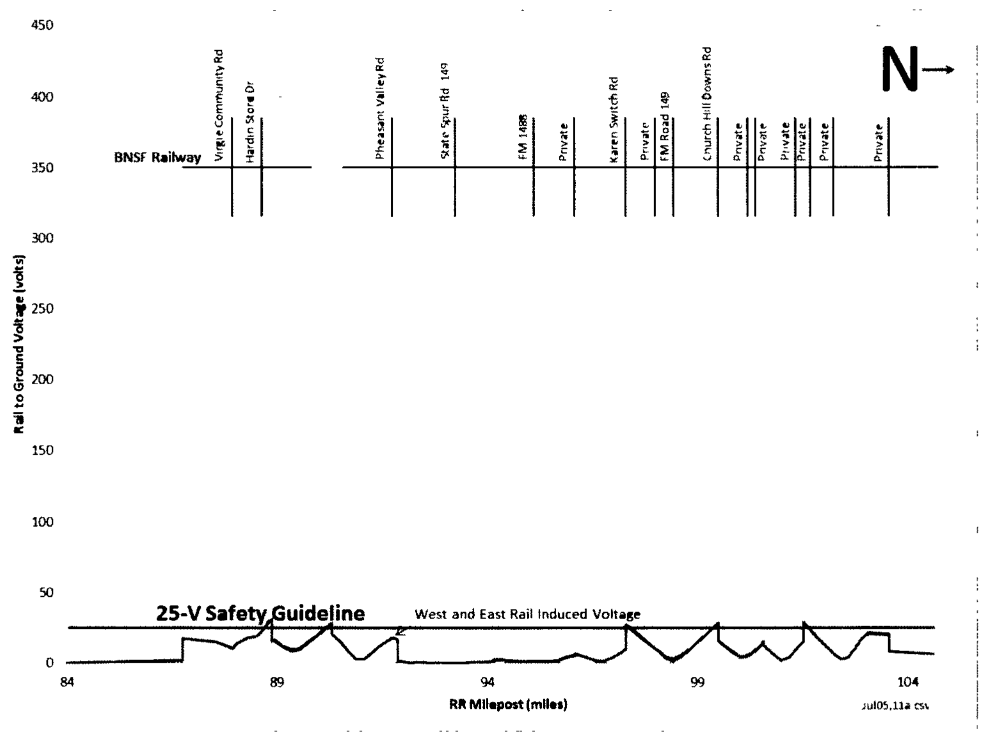

Figure 10. Predicted Steady-State Rail to Ground Voltage for Circuits 74C and 75B Energized with Mitigation Alternative B Modeled.

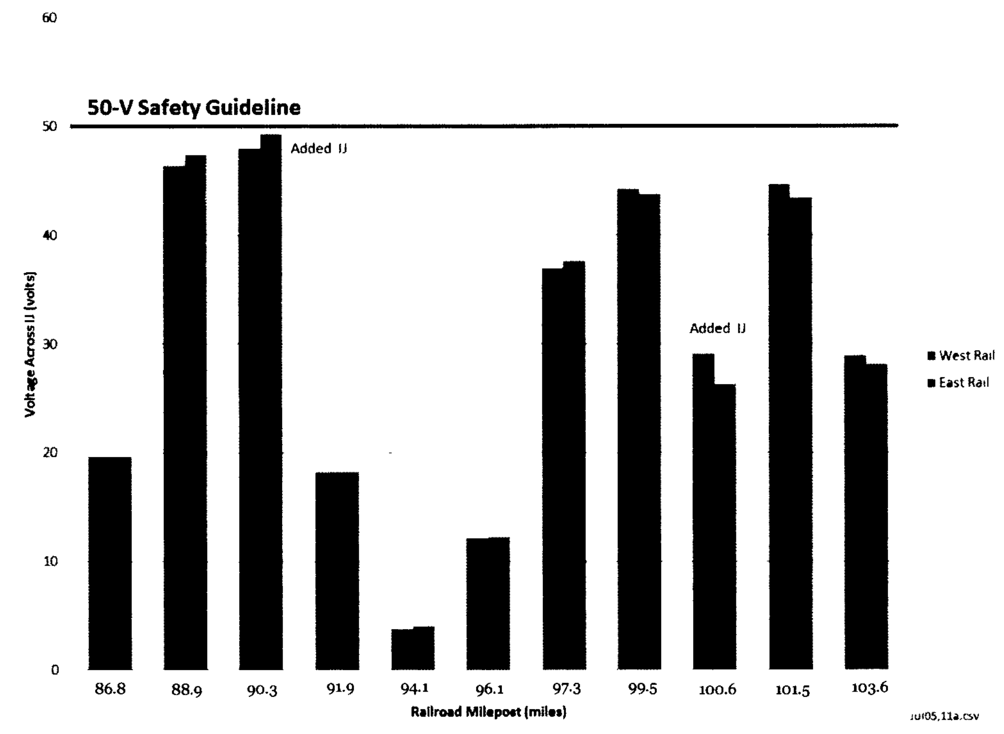

Figure 11. Predicted Steady-State Voltage Across Insulated Joints for Circuits 74C and 75B Energized with Mitigation Alternative B Modeled.

Mitigation Alternative C

Special equipment was installed to monitor the existing power line currents in April 2011, for the purpose of using the data to corroborate the model and to characterize the residual current on the line. A description of the field-measured data and analysis is shown in Appendix B. This analysis led to the belief that the net or effective residual current with the new power configuration with both circuits energized would likely be below 3.5%. The term "net residual" reflects the possibility that the magnitude of the residual current in each circuit may be higher than the net or effective residual of both circuits together, as is described in Appendix B. Thus, additional analysis was performed to investigate a mitigation alternative in which 4% net residual current was used instead of 7.2%. Four percent was used instead of 3.5% to be conservative.

The mitigation measures that were modeled assuming a net 4% residual current are labeled Mitigation Alternative C. Mitigation Alternative C is the same as Mitigation Alternative B with the only exception being that in C there are no added track insulated joint locations. With 4% residual current used in modeling, no added insulated joints were needed to reduce the maximum predicted accessible voltage to below the 50-V safety guideline. Figure 12 shows the predicted rail to ground voltages on the track with Mitigation Alternative C modeled. The maximum predicted voltage across the insulated joints for Mitigation Alternative C is shown in Figure 13. The maximum IJ voltage is calculated to be 49.7 V at one location, which is very close to the safety guideline, but the voltage at other IJ's are comfortably less than 50 volts. The induced voltage will be less for all other steady state power loading, except emergency loading of both circuits. This mitigation alternative is recommended as another viable option, assuming that 4% net residual current or less is expected on each circuit of the transmission line, consistent with the measured data.

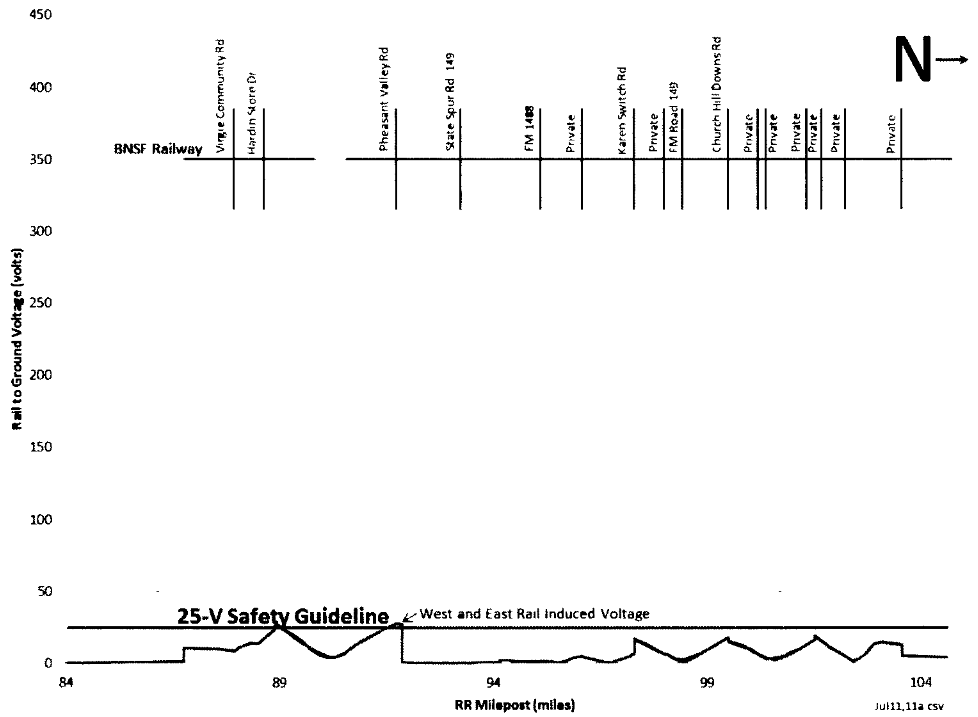

Figure 12. Predicted Steady-State Rail to Ground Voltage for Circuits 74C and 75B Energized with Mitigation Alternative C Modeled.

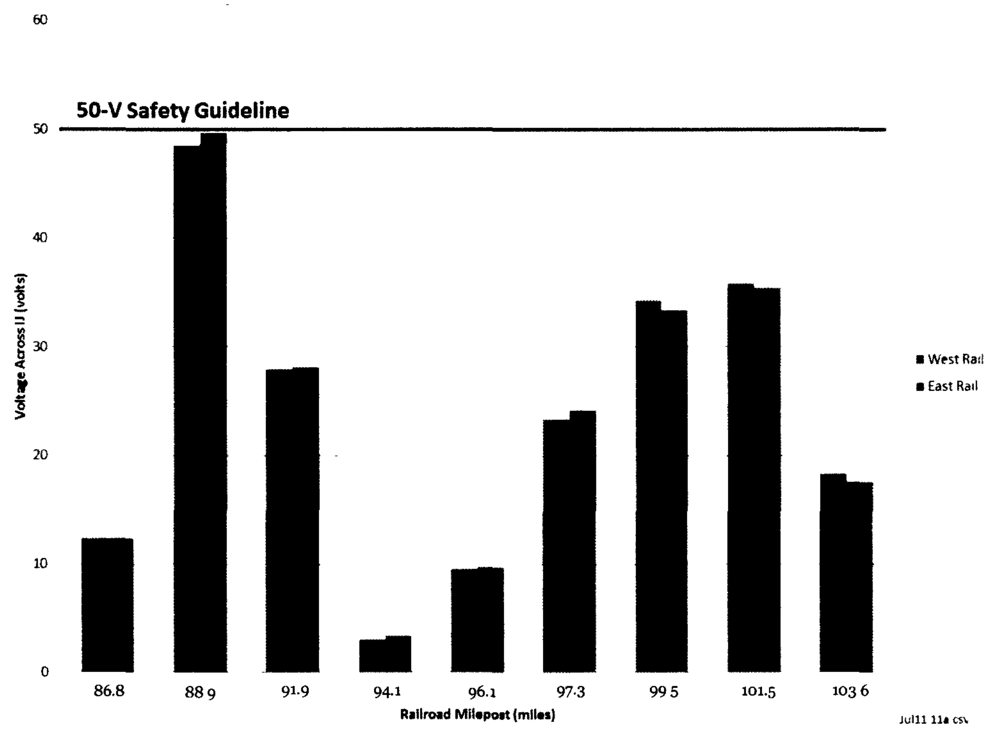

Figure 13. Predicted Steady-State Voltage Across Insulated Joints for Circuits 74C and 75B Energized with Mitigation Alternative B Modeled.

STOPPED TRAIN CONDITION

Another track condition that may cause higher than normal steady-state induced track voltage is when a train stops on the tracks and shorts out one or more pairs of IJ's. For steady-state conditions OSHA has set 50-V as an implicit standard for the safe touch potential limit, which is commonly used. The standard states, "Live parts of electric equipment operating at 50 volts or more shall by guarded against accidental contact by approved cabinets or other forms of approved enclosures."[3] The Canadian rail induced voltage standard identifies 50-volts across an insulated joint as a safe accessible voltage. Therefore an acceptable rail to ground voltage criteria for a person contacting a train in an exposure is identified as 50 V.

The stopped train condition analysis assumes that the train will short-out all track IJ's within the length of the train. The maximum train-to-ground voltage occurs when the train is stopped on either side of an

[3] OSHA Title 29, Volume 5, CFR Ch. XVII (7-1-98 Edition) Sec. 1910.303, Page 826-831, U.S. Government Printing Office.

IJ, but not shorting the IJ. For the analysis, a simulated 8000-ft. train was systematically moved to each IJ location, with all the IJ's within the length of the train shorted. Both circuits 74C and 75B were energized for this analysis. Mitigation Alternatives A, B, and C were all analyzed for the stopped train analysis as well.

Figures 14-16 below show the predicted maximum train-to-ground voltage for Mitigation Alternatives A, B, and C respectively. These figures show that the accessible voltage on a stopped 8,000-ft long train is predicted to be no more than 45 V, which is less than the 50-volt safe touch potential guideline. Therefore, no additional mitigation due to the stopped train condition should be necessary with respect to each of the three mitigation alternatives. The lowest maximum stopped train voltage profile is for Mitigation Alternative C.

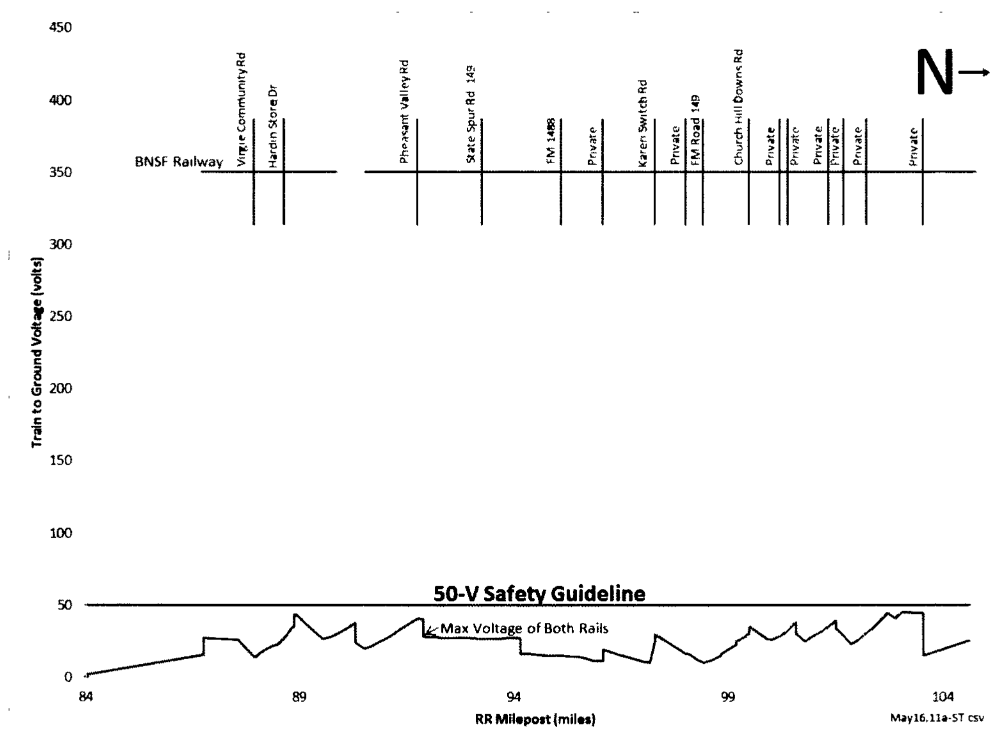

Figure 14. Predicted Maximum Steady-State Train to Ground Voltage for Circuits 74C and 75B Energized with Mitigation Alternative A Modeled.

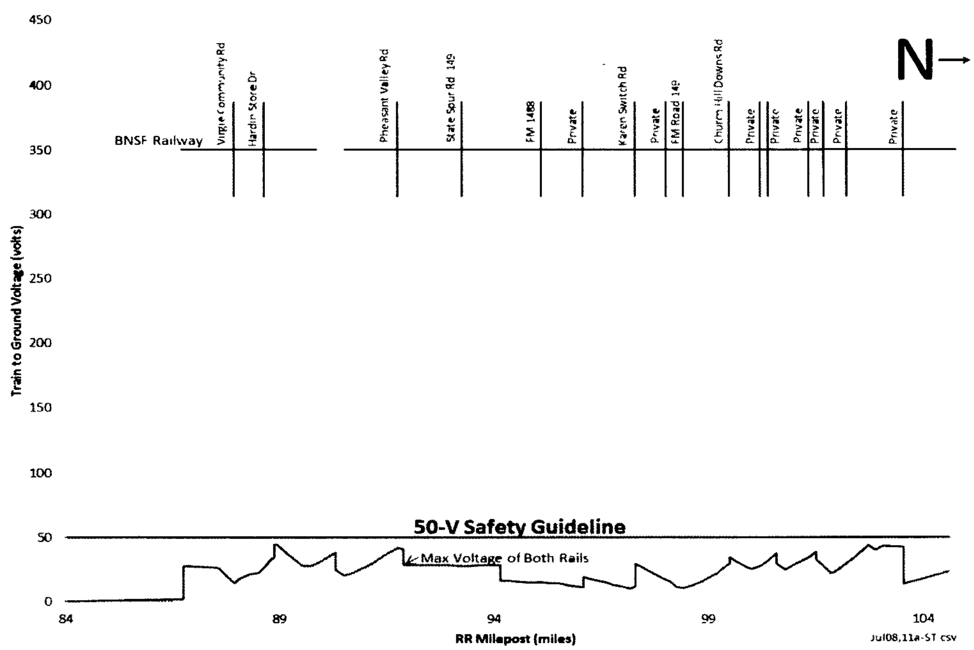

Figure 15. Predicted Maximum Steady-State Train to Ground Voltage for Circuits 74C and 75B Energized with Mitigation Alternative B Modeled.

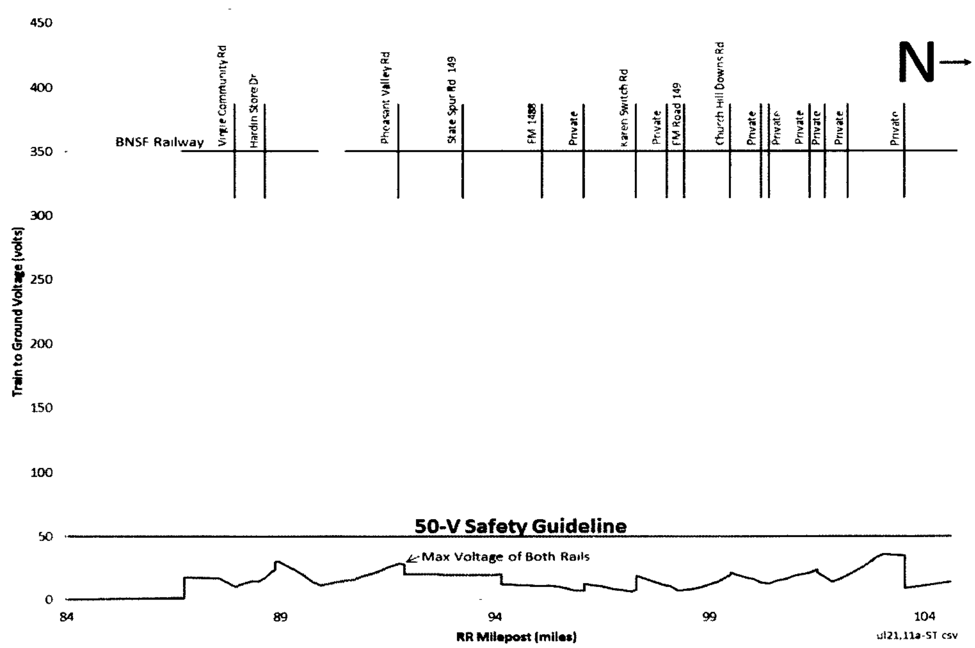

Figure 16. Predicted Steady-State Train to Ground Voltage for Circuits 74C and 75B Energized with Mitigation Alternative C Modeled.

FAULT CONDITION

A single phase-to-earth fault along a transmission line results in a high current in the faulted phase, which can be considerably higher than the normal load current. The high current only exists for a brief period (approximately 67-milliseconds or four cycles for this transmission line), since sensing circuits on the power system will open breakers to stop the flow of current. The high fault current in the transmission line conductor creates a high magnetic field, which can induce high voltage and current in long parallel conductors such as a rail system or pipeline. Figure 17 shows the approximate single phase to ground fault current of circuit 74C:

- that is supplied to the fault location from the Tomball Substation,
- that is supplied to the fault location from the Singleton Substation,
- and the total fault current,

as a function of the fault location in the exposure region. Figure 18 shows similar data for circuit 75B for contribution to the fault from the Kuykendahl Substation, from the Roans Prairie Substation, and the total fault current. CenterPoint supplied single phase fault current information that was used to interpolate the values for Figures 17 and 18.

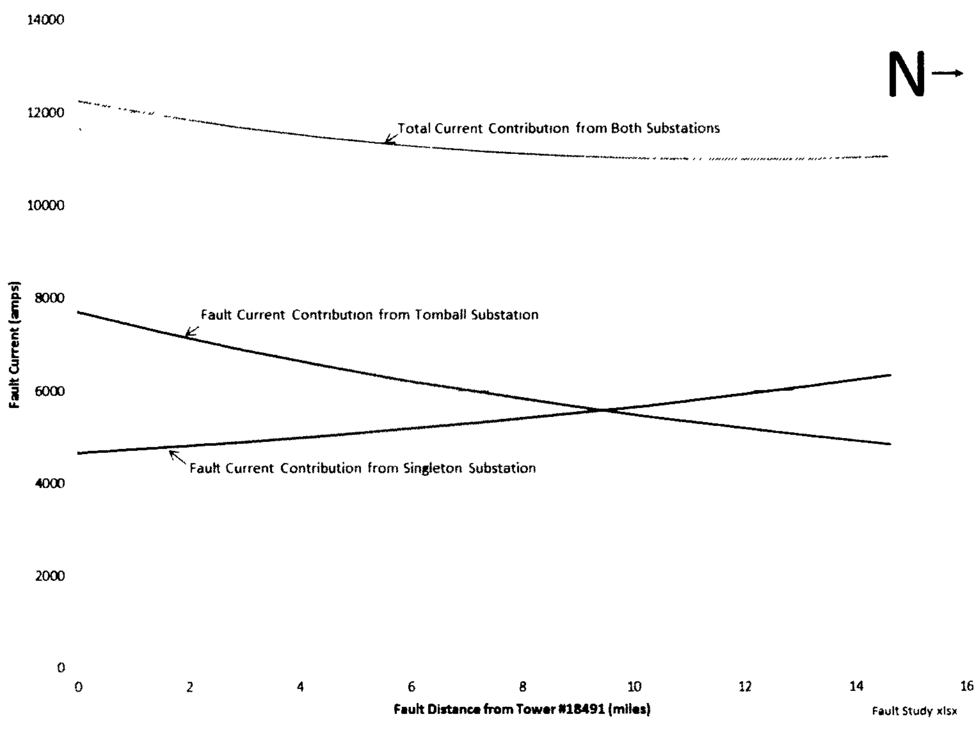

Figure 17. Approximate Single Phase to Ground Fault Currents for Circuit 74C.

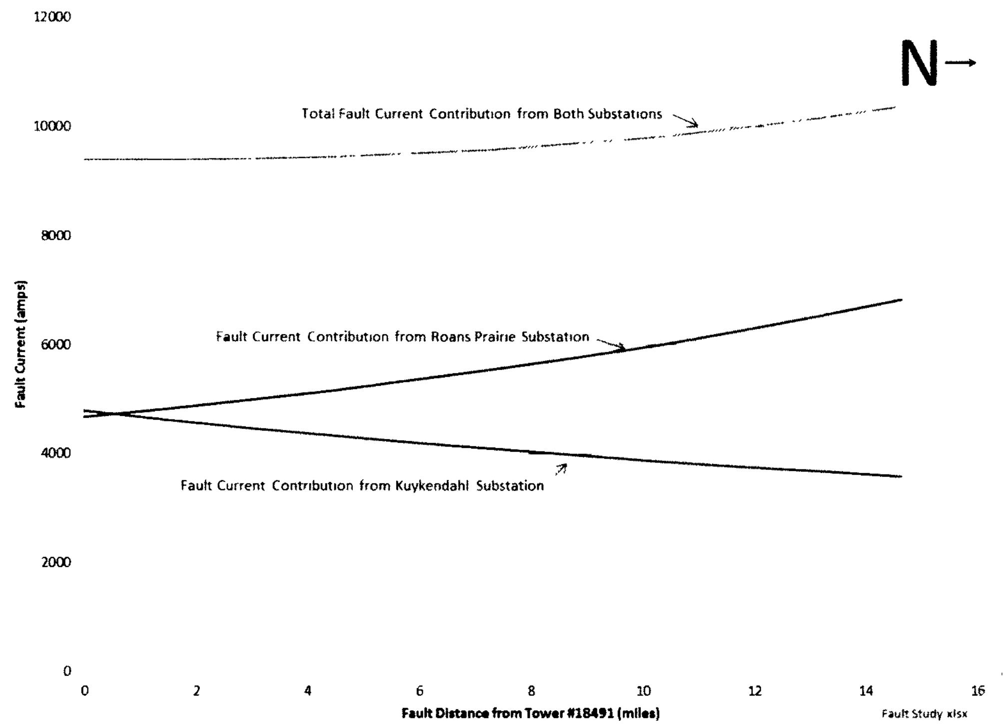

Figure 18. Approximate Single Phase to Ground Fault Currents for Circuit 75B.

A single phase-to-transmission structure fault that occurs within the exposure results in high current flow to earth at the faulted structure and other nearby transmission line structures that are connected together by the overhead shield wire (OHSW). The current that flows back toward the substation through the OHSW tends to cancel the field effect of the current in the faulted conductor, thus providing a shielding function. Other high-conductivity conductors that may be placed on the transmission line (as a mitigation) and are grounded to the towers will also carry fault current back toward the substation, thus further reducing the magnetic field at nearby parallel conductors, such as railroad tracks.

The railroad signal equipment is protected against high-current events, such as lightning, by lightning arresters that are installed at signal-equipment locations. These lightning arresters will fire if the fault-induced rail to ground voltage exceeds the spark-over potential of the arresters. The fired arresters will protect the railroad signaling equipment from damage during the short duration of the fault if the fault-induced current that flows through the arrester does not exceed the arrester rating. Thus, one of the compatibility conditions of concern for the fault condition is to evaluate the current that may flow through fired railroad signal-system lightning arresters relative to the current that may cause failure of an arrester. For the faulted power condition, the principal concern is for the survivability of both personnel and railroad communications/signal equipment.

PERSONNEL SAFETY

Track maintenance personnel and the public who contact the rails and equipment enclosures at any location along the exposure, and possibly beyond, should be considered in evaluating the possible hazards associated with a transmission line fault. An investigation of the fault condition was performed to assess the need for mitigation to maintain a safe rail touch potential. Faults were simulated at eleven equally spaced locations along the exposure for both circuits 74C and 75B using the fault-current contributions from Figure 17 and Figure 18 respectively. Analysis performed early in the investigation showed that faults on circuit 74C would induce higher voltage on the tracks than faults on circuit 75B. This is due to circuit 74C being closer to the tracks than circuit 75B for most of the exposure. Thus, circuit 74C was used to determine worst-case results.

Mitigation Alternatives A, B, and C were analyzed for the fault condition. The results of this analysis are presented below in Figures 19-21 for the case of the track lightning arresters not fired and Figures 22-24 for the case of all the track lightning arresters fired within the exposure, respectively. The figures show the predicted induced rail to ground voltage on the track throughout the exposure. Each figure shows, for each location along the exposure, the maximum rail to ground voltage that results from all eleven simulated faults. The figures also include the location of street crossings to help the reader relate the induced voltages with a specific location. The maximum induced voltage of both rails has been plotted.

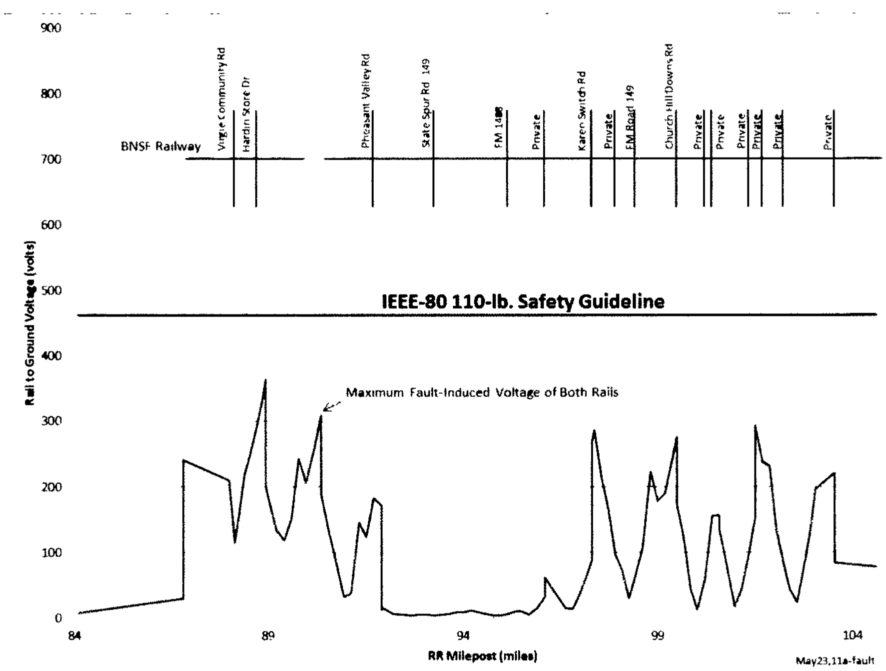

Figure 19. Predicted Fault-Induced Rail to Ground Voltage for a Fault on Circuit 74C with Mitigation Alternative A Modeled and Track Lightning Arresters NOT Fired (Composite of All Eleven Simulated Faults).

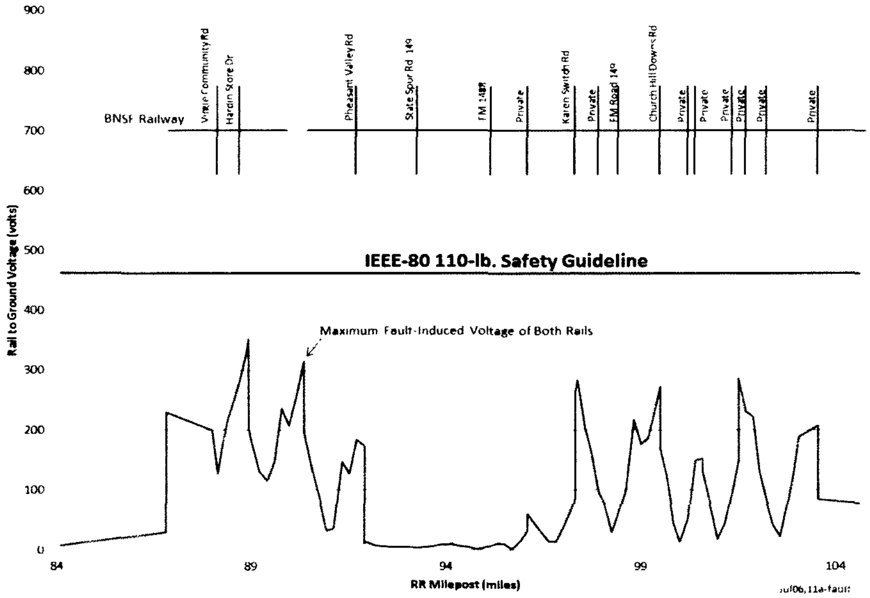

Figure 20. Predicted Fault-Induced Rail to Ground Voltage for a Fault on Circuit 74C with Mitigation Alternative B Modeled and Track Lightning Arresters NOT Fired (Composite of All Eleven Simulated Faults).

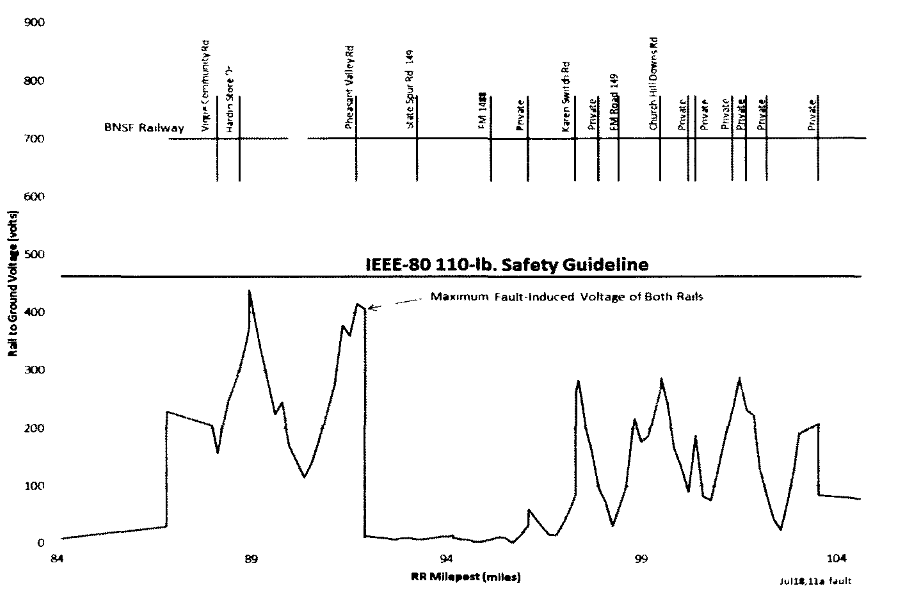

Figure 21. Predicted Fault-Induced Rail to Ground Voltage for a Fault on Circuit 74C with Mitigation Alternative C Modeled and Track Lightning Arresters NOT Fired (Composite of All Eleven Simulated Faults).

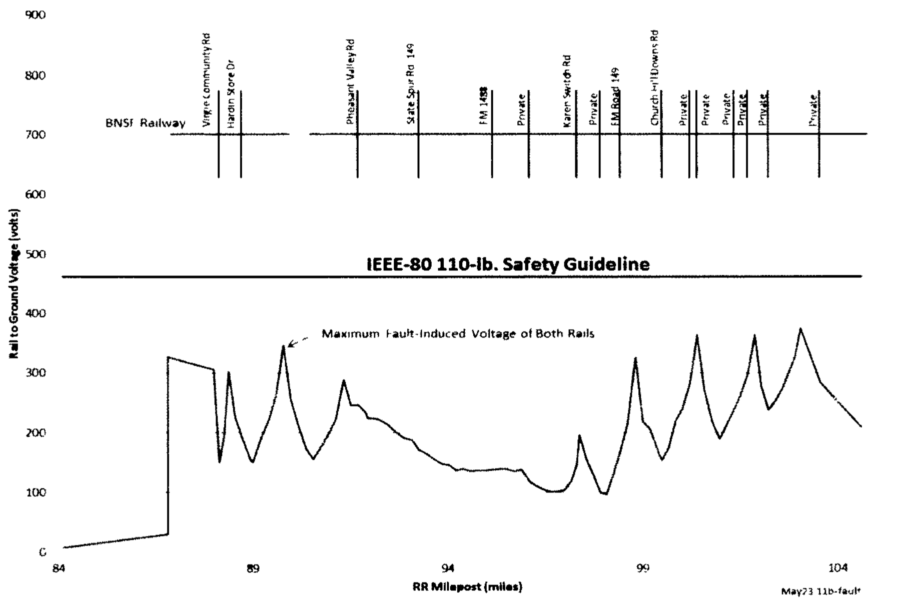

Figure 22. Predicted Fault-Induced Rail to Ground Voltage for a Fault on Circuit 74C with Mitigation Alternative A Modeled and Track Lightning Arresters Fired (Composite of All Eleven Simulated Faults).

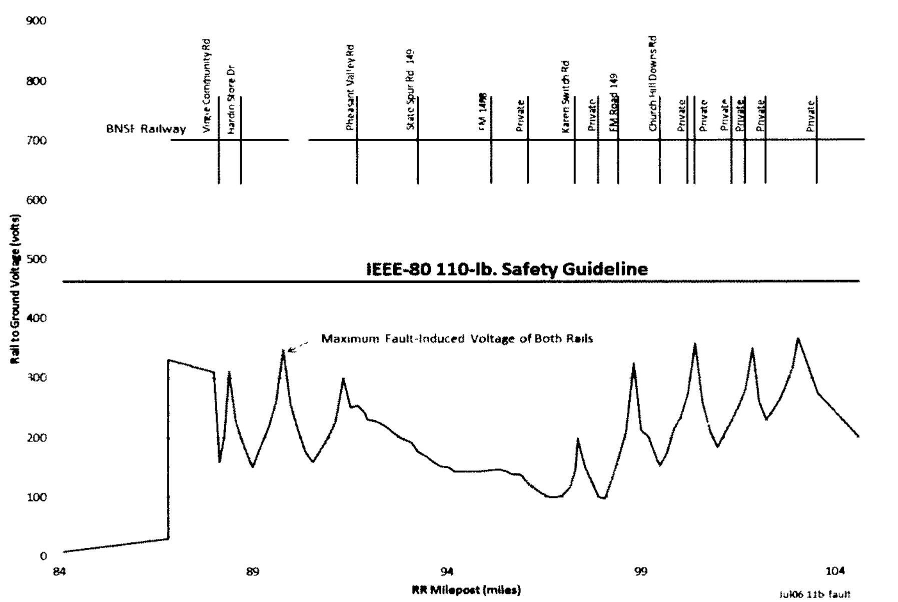

Figure 23. Predicted Fault-Induced Rail to Ground Voltage for a Fault on Circuit 74C with Mitigation Alternative B Modeled and Track Lightning Arresters Fired (Composite of All Eleven Simulated Faults).

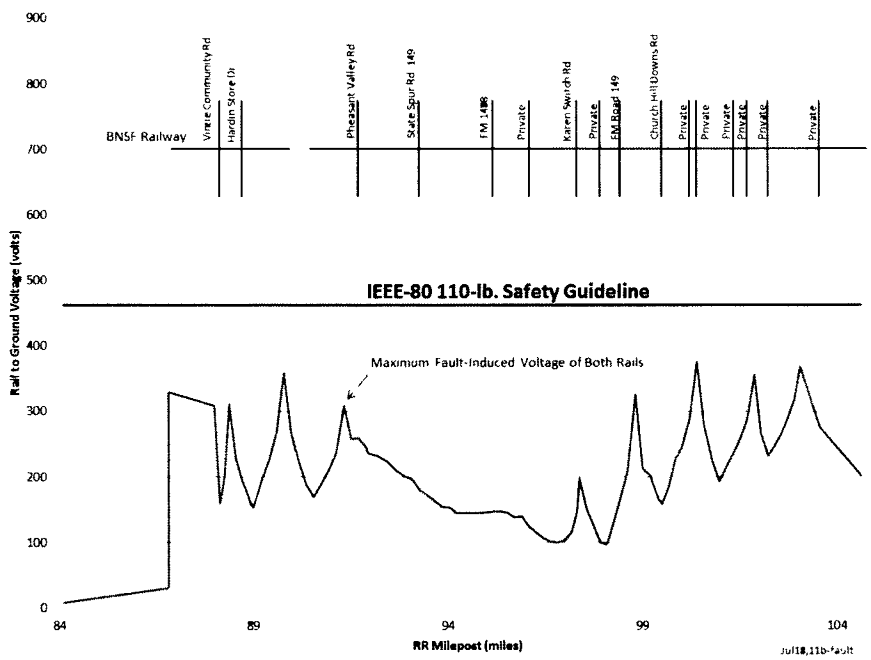

Figure 24. Predicted Fault-Induced Rail to Ground Voltage for a Fault on Circuit 74C with Mitigation Alternative C Modeled and Track Lightning Arresters Fired (Composite of All Eleven Simulated Faults).

The safe touch potential value for a 110-lb person has been derived from IEEE Std. 80-2000 using 18.2 ohm·m as the soil resistivity and using a 4-cycle fault clearing time.[4] The calculated safe touch value is 462 V, which assumes that the person is standing on native soil with no impedance due to footwear. This value is represented on the plots by a horizontal line which expresses that 99.5% of persons of that weight are expected to survive the event.

Any fault-induced rail to ground voltage that is higher than this touch potential line may be less safe for a person of this body weight. Larger persons are safe for higher rail to ground voltage. A broader AAR guideline (the Blue Book) states that 650 V ac rms is safe for high reliability power lines with high speed

[4] *IEEE Std 80-2000: IEEE Guide for Safety in AC Substation Grounding*, The Institute of Electrical and Electronics Engineers, Inc. (IEEE, Inc.), 3 Park Avenue, New York, NY 10016-5997.

fault clearing.[5,6] However, it is felt that the IEEE Std. 80 calculated value of 462 V is more conservative, and so it has been used as a target guideline for this investigation.

Figures 19-24 show that the calculated induced rail to ground voltage on the BNSF tracks is less than the safe touch potential guideline for a 110-lb person (462 V). The rail-ground voltages of Figures 19-21 suggest that the arresters may not fire, because the predicted induced voltage is less than the expected track arrester arc-over voltage. Thus, no additional mitigation is recommended for personnel safety specifically for the fault condition.

TRACK LIGHTNING ARRESTER SURVIVABILITY

The railroad signal equipment is protected against high-current events, such as lightning, by lightning arresters that are installed at signal-equipment locations. These lightning arresters will fire if the fault-induced rail-to-ground voltage exceeds the spark-over potential of the arresters. We have assumed for this mitigation analysis that the track lightning arresters in the exposure would fire due to a transmission line fault, if the rail to ground track voltage exceeds 600 V. This assumption was made using available information from arrester manufacturers. The analysis results shown in Figures 19-21 illustrate that the predicted rail to ground voltages with the proposed mitigation alternatives do not exceed 600 V in the exposure. However, to be conservative we have assumed the arresters may fire during a fault event.

The fired arresters will protect the railroad signaling equipment from damage during the short duration of the fault if the fault-induced current that flows through the arrester does not exceed the arrester rating. Thus, one of the compatibility conditions of concern for the faulted condition is to evaluate the current that may flow through fired railroad signal-system lightning arresters relative to their rated current. For the faulted power condition, the principal concern is for the survivability of both personnel and railroad communications/signal equipment.

The only known published data available on the 60-Hz fault withstand of standard railroad lightning arresters showed the USG arresters survived up to 200,000 I^2t of 60-Hz energy without shorting, whereas the data show that other popular track arresters (e.g. Safetran Clear View and Heavy Duty arresters) failed shorted or were destroyed at lower energy levels (I^2t in the range 12,500 to 50,000)[7]. Therefore, a fault capacity (I^2t) of approximately 100,000 for available heavy-duty lightning arresters is typically assumed, based on the USG data. The rated arrester current is determined from the equation,

$$I^2t = 100{,}000 \text{ amps}^2\text{·seconds}$$

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[5] *Principles and Practices for Inductive Coordination of Electric Supply and Railroad Communication/Signal Systems*, Association of American Railroads, September, 1977.
[6] Reference [3] cites the 650-V fault touch-potential guideline with high-speed clearing as: CCITT *Directives concerning the protection of telecommunication lines against harmful effects from electric power and electric railway lines*, Volume VI, Danger and Disturbance.
[7] "60 Hz Fault Current Withstand Tests on Signal Lightning Arresters", C&S Division, AAR Committee Reports and Technical Papers, 1984.

where ***t*** is the fault clearing time in seconds (67 ms), and ***I*** is the current the arrester can withstand in amps. This results in a current capacity of approximately 1.221 kA for the expected fault clearing time of this exposure.

The current that is predicted to flow through the fired arresters when Mitigation Alternatives A, B, and C are modeled does not exceed 274 A, 274 A, and 272 A respectively at any location, which is significantly less than 1.221 kA. Thus, no supplemental mitigation is recommended with respect to railroad lightning arrester survivability as long as heavy-duty track lightning arresters such as the USG-A are used in the exposure region.

SELECTED MITIGATION

At the Design Review Meeting on December 6, 2011, the results of the mitigation design study were presented to CNP and BNSF. The three effective mitigation alternative packages were described in detail and the initial reaction by both organizations was to pursue Option C. It was later confirmed by CNP that they and BNSF had decided to pursue Option C.

Discussions that began at the design review meeting resulted in reanalysis of some aspects of the extent and positioning of both the aerial and shield wires. The specific items investigated were:

- Localized adjustments of the position of the aerial shield wire to accommodate
  - blowout clearances of the transmission line
  - a third-party distribution line
  - a lake
  - road crossings
- Localized adjustments of the position of the buried shield wires to accommodate:
  - road crossings
  - Stream crossings
- Omitting the shield wires in a portion of the right-of-way where the distances between the track and the transmission line are substantially greater than the typical spacing.

These adjustments were evaluated by selectively modeling only the cases that were previously shown to be the worst-case conditions. These selective data did not indicate significant increases in the induced energy. So, we can conclude that these changes will *probably* not result in unacceptable voltage under worst-case conditions. Without repeating the exhaustive analysis, we cannot be *certain*.

The reason that we are confident of the safety of this adjusted mitigation plan is based in the fact that the selected mitigation includes a post-installation study of mitigation effectiveness. This study will involve recording voltages and currents on the transmission line and on the railroad tracks, and comparing these actual values against those predicted by the computer model. These results will then be extrapolated to worst-case conditions using the model. If any deficiencies are identified, further mitigation can be implemented.

This section of the report is directed toward specific installation aspects of Option C, as amended.

Installation Details

Option C includes three types of mitigation:

- Transposition of phase wires
- Aerial shield wire
- Buried shield wires

There are sub-sections for each of these types of mitigation.

There is also a section on the testing of buried shield wires. This section includes details about the installation of test points to facilitate future testing.

Finally, there is a section on the post-installation testing that is a necessary part of Option C.

Transposing Phase Wires

A phase change is recommended in circuit 74C. The A and B phases switch location as shown in Figure 25 below. The left configuration is the existing configuration, and the right configuration is the arrangement recommended. The analysis results that provide the basis for the recommended phase configuration change is shown in Appendix A.

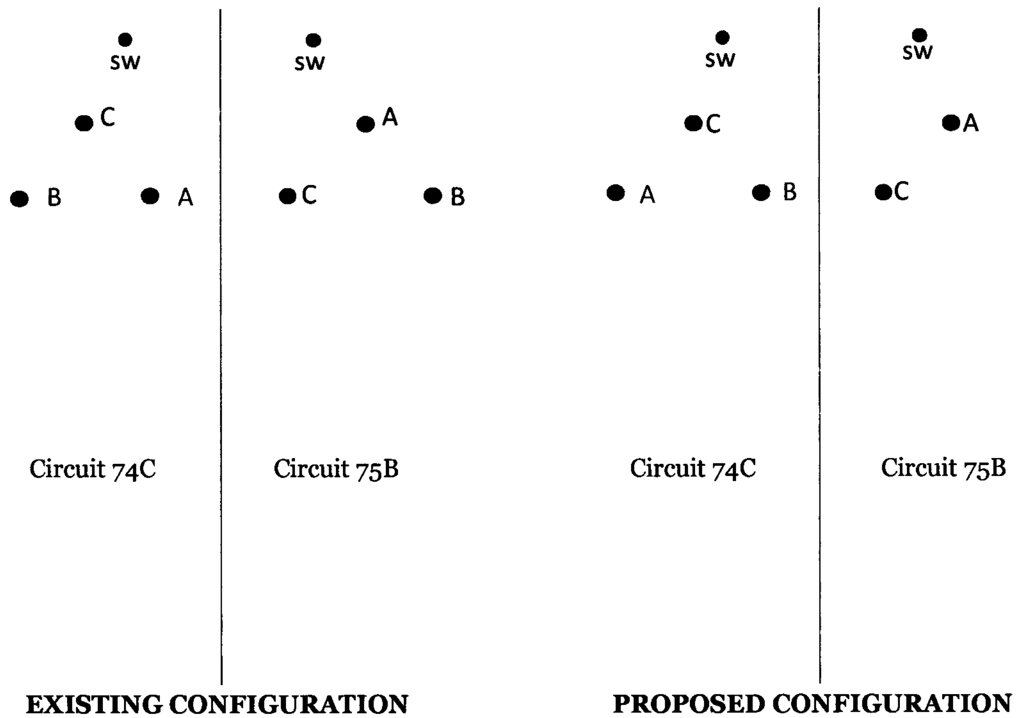

Figure 25. Phasing Arrangements for the two CNP Circuits (Looking North in Exposure Region).

Aerial Shield Wire

The aerial shield wire is in three segments as detailed below.

Structures 18494 to 18487 (Vertical Region)

Install one 636 MCM Rook ACSR aerial conductor extending from tower 18494 to tower 18487. It is recommended that the conductor be:

- strung underbuilt on the transmission structures,
- electrically continuous from tower 18494 to tower 18470,
- strung 10 ft. vertically below the mean height of the lowest phase conductor for the condition of greatest phase-conductor sag (248°F),
- and electrically-grounded at all poles with a 5-ohm impedance to ground.

Structures 18486 to 18470 (Delta Region)

Install one 636 MCM Rook ACSR aerial conductor extending from tower 18486 to tower 18470. It is recommended that the conductor be:

- strung on separate poles that run parallel to the power line,
- 57 feet west of the centerline of the power towers
- electrically continuous from tower 18494 to tower 18470,
- strung 10 ft. vertically below the mean height of the lowest phase conductor for the condition of greatest phase-conductor sag (248°F),
- and electrically-grounded at all poles with a 5-ohm impedance to ground.

Between structures 18486 and 18487 the aerial shield wire must be electrically continuous, but the transition can be made at either structure, or anywhere between the structures, in the most convenient manner.

Structures 21257 to 2394

Install one 636 MCM Rook ACSR aerial conductor extending from tower 21257 to tower 2394. It is recommended that the conductor be:

- strung on separate poles that run parallel to the power line,
- 62 feet west of the centerline of the power towers
- electrically continuous from tower 21257 to tower 2394,
- strung 10 ft. vertically below the mean height of the lowest phase conductor for the condition of greatest phase-conductor sag (248°F),
- and electrically-grounded at all poles with a 5-ohm impedance to ground.

For any of the aerial shield wires localized deviations in the alignment can be made to accommodate clearance or other issues. However, it is important that the shield wires be electrically continuous.

Buried Shield Wires

The buried shield wire is in two segments as detailed below. Each segment consists of four wires buried along the railroad track, two wires on each side, as shown in Figure 26.

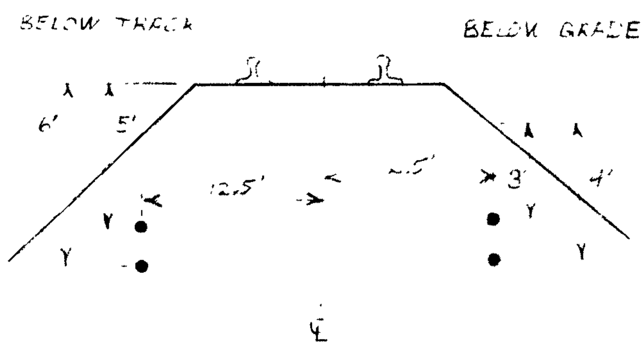

Figure 26. Buried shield wire positions

Common characteristics of all shield wires are:

- 500 MCM bare copper conductor,
- 12.5 ft. from the BNSF track centerline,
- parallel to the BNSF track,
- do not touch each other,
- and electrically continuous throughout.

There is one trench on each side of the track. Each trench has two wires as follows:

- The top wire installed 5 feet below the track or 3 feet below grade
  - If there is sufficient cover, bury 5 feet below the track
  - If there is not sufficient cover at 5 feet below the track, then bury lower to get sufficient cover (~ 3 feet below grade)
- The bottom wire installed 1 foot below the top wire

Buried shield wires can often be installed using rail mounted plows. This method often results in the least disruption of the ballast.

MP 88.0 to MP 92.2

One segment of buried shield wire extends between the following two railroad mileposts (MP):

- MP 88.0 (N30° 08.49' W95° 38.12' +/- 50 feet)
- MP 92.2 (N30° 11.65' W95° 40.06' +/- 50 feet)

MP 96.0 to MP 103.55

The other segment of buried shield wire extends between the following two railroad mileposts (MP):

- MP 96.0 (N30° 14.45' W95° 41.74' +/- 50 feet)
- MP 103.55 (N30° 20.15' W95° 45.27' +/- 50 feet)

Buried Shield Wire Test Points

Test points are used to monitor the integrity of underground counterpoise wires throughout the life of the installation. While most underground counterpoise installed over the last few decades do not undergo periodic testing, we recommend the practice out of an abundance of caution. Test points are installed during the installation of the counterpoise to facilitate these future tests. Even if a program of periodic testing is not pursued, the installation of test points is recommended to allow for the testing of the counterpoise if other factors, such as an unexpected rise in rail voltages, indicate that the counterpoise may have been compromised.

Test points typically consist of a hand-hole mounted flush with the surface of the ground. Inside the hand-hole is the top end of a wire that is bonded to the counterpoise at the bottom. These test points are typically at ½ -mile intervals.

When testing, a current source is connected to the wire at the test point (typically 4 Hz at 3 amperes). A test instrument on the surface then detects this current in the counterpoise. Because of the strong presence of 60 Hz in our environment, the reliable range from the current injection point is limited. That is why test points are recommended at ½-mile intervals.

For testing to be effective, it is recommended that the four buried shield wires never touch each other. This may be difficult since each pair of wires is installed only one foot apart. But if two wires touch, then a broken wire might appear as if it was intact when tested.

In the past, JWS Services has provided testing for buries shield wires. Their web site is http://www.jwspiservices.com/.

Post-Installation Study

The selected mitigation for this project includes a program of post-installation testing to verify the effectiveness of the mitigation under all anticipated system conditions.

The adjustments to the mitigation plans were evaluated by selectively modeling only the cases that were previously shown to be the worst-case conditions. These selective data did not indicate significant increases in the induced energy. So, we can conclude that these changes will *probably* not result in unacceptable voltage under worst-case conditions. But without repeating the exhaustive analysis, we cannot be *certain*.

The reason that we are confident of the safety of this adjusted mitigation plan is based in the fact that the selected mitigation includes a post-installation study of mitigation effectiveness. This study will involve recording voltages and currents on the transmission line and on the railroad tracks, and comparing these actual values against those predicted by the computer model. These results will then be extrapolated to worst-case conditions using the model. If any deficiencies are identified, further mitigation can be implemented.

The monitoring for this study should be for two months during the highest load part of the year (summer). This duration of testing should result is the capture of data under a variety of circumstances.

The post-installation testing will be performed under a separate contract.

CONCLUSIONS

This study has investigated the existing circuit 74C and circuit 75B 345-kV transmission lines for estimated railroad induction using current data provided by CenterPoint for steady-state and fault conditions. The compatibility of both of these transmission lines with the nearby BNSF railroad system is quantified in this report.

The analysis shows that additional mitigation will be needed specifically for the steady-state condition of the transmission line in order to reduce the predicted induced track voltage to below the 50-V safety guideline. The need for mitigation has been identified according to the following safety guidelines for steady-state and fault conditions:

- The steady-state safety limit of 50 V (accessible) rail-to-ground and across any insulated joint.
- The steady-state train to ground safety limit of 50 V for a person contacting a stopped train.
- The allowable safe touch potential for a person contacting the tracks during a 4-cycle fault on either circuit of the transmission line is calculated using IEEE Std. 80 procedures to be 465 V for a 110-lb. person.

Three functional mitigation alternatives (A, B, and C) were developed by iterative analyses. The three mitigation alternatives listed reduce the predicted line steady-state induced track voltage to below the 50-V safety guideline throughout the exposure for the BNSF. These same mitigation measures reduce predicted fault-induced track voltages throughout the exposure to below the applicable safety guideline as well. Any of the three mitigation alternatives for this exposure would be effective. However, it should be noted the Mitigation Alternative C requires specific assumptions with respect to the residual current on both circuits 74C and 75B, namely that the net residual current is assumed to be 4% or below in each circuit instead of 7.2%.

Mitigation Alternatives A and B both require changes to the BNSF railroad system in that two new insulated joint locations and associated rack-signal repeater equipment would need to be added to the exposure. Mitigation Alternative C does not require changes to the BNSF railroad signal system.

All of the mitigation measures listed in this report have been implemented in previous exposures studied. Every effort has been made to mitigate compatibility issues within the exposure with the least railroad-intrusive methods, while maintaining mitigation effectiveness.

APPENDIX A: EXPLANATION OF FIELD DATA USED TO CHARACTERIZE RESIDUAL CURRENT

Introduction and Overview of Measurements and Results

This appendix describes field-measured data, preliminary analysis of that data and conclusions derived from the data and analysis, as a part of the ongoing CenterPoint/BNSF compatibility investigation being conducted by EISI and Corr Comp. Line voltage and current were logged at two CNP substations that supply power to the two transmission circuits being investigated that nominally parallel the BNSF rail line, which are described in the main text of this report. Simultaneous rail voltages were logged at two signal locations on the associated BNSF track that had experienced high 60-Hz rail-to-ground voltage. The purpose of the monitoring was threefold:

- To obtain further evidence that the 60-Hz rail-to-ground voltage was related to the transmission line load current,
- To compare the measured data with the model of the exposure, to build further confidence in the model prior to using the model to develop mitigation measures,
- To better quantify the influence of transmission line load current unbalance on the 60-Hz voltage that is induced onto the track.

Usable data were obtained for approximately a one-week period with both transmission circuits energized and for approximately a one-week period with only one transmission circuit energized. Although the data-collection period was relatively short, the data were extremely beneficial in helping to achieve the three objectives outlined above.

The data show an unmistakable correlation between transmission line load current and induced rail voltage as is illustrated in Section 7 of this appendix. Thus, the data clearly establishes that the 60-Hz rail voltage is caused by the transmission line current.

Measured transmission line currents at representative times of "high" and "low" load current during the measurement period were used in the computer model of the exposure that we had developed. At the two locations chosen for monitoring rail-induced 60-Hz voltage, the "high load" period resulted in 55-60V rail-to-ground voltage and the "low load" period resulted in 35-38V rail-to-ground voltage. The model was used to calculate induced rail voltage for those measured values of transmission line currents. The calculated induced rail voltages at those two time snapshots show excellent agreement (within one volt) of the corresponding measured rail voltages, when the appropriate values of power current are used in the model. Those results are presented in Section 8 of this appendix and establish the validity of the model for use in extrapolating to other conditions such as with applied mitigation measures.

Section 3 of this appendix shows that the measured unbalance component of current in the double-circuit transmission line can be decomposed into two components, i.e. differential and common mode. The common mode component of the double-circuit residual current is the same magnitude and phase in each circuit. Only the common-mode component of the double circuit residual current and the balanced current (positive sequence current) from each circuit contributes significantly to the induced rail voltage. The measurement results presented in Section 6 of this appendix illustrate that the unbalanced current contribution to induced rail voltage is expected to be approximately ½ as large as originally estimated by CNP and initial measurements made in 2008. The original steady state unbalanced current estimates are used for Mitigation Alternatives A and B of the main text, whereas the unbalanced current estimate based on this appendix are used for Mitigation Alternative C of the main text.

Discussion of Transmission Line Current Monitoring Installation

This appendix considers data logged on Ckt 74C at the Singleton substation and Ckt 75B at the Roans Prairie substation and two locations on the BNSF system during two time periods. The first time period is from March 31 through early April 6, 2011 for which 4-channel current probe data (three phase currents and a "residual" current) were logged at the two substations with both power circuits active. Those data are discussed in Section 3. The second period is from April 6 through April 12, 2011 for which only the Singleton Circuit was energized. Those data are discussed in Section 4. Section 6 provides a summary of analysis that has been made to better understand the data and how the results might affect the ongoing mitigation design. Section 7 reviews BNSF track induced voltage data obtained during the same time period, with emphasis on demonstrating correlation with the substation data and the efficacy of the computer model being used to develop mitigation measures.

The purpose of this appendix is to consolidate important results from the testing and our understanding of the data. This information provided a basis for discussing how to best use the field test data to benefit the ongoing mitigation design effort. The information is relevant to the mitigation design, since analysis indicates that steady state induction with both circuits energized at full load is the condition that necessitates most mitigation. The remainder of this introduction provides some technical information on the data collection procedures and initial processing of the data.

Data were monitored and logged using a Dranetz 4400 power quality meter that records four channel voltage and current values on a sampled basis. One voltage and current channel is for each of the A, B, and C phase current and voltage. A fourth "D" channel can be used to log residual or unbalanced components of current. The D-channel current was monitored differently at the two substations. At Roans, the D-channel current probe monitored the common 4th return conductor of the CT's. The direction of the D-channel probe was opposite of the A, B, C probes. Therefore, the phase of the logged D-channel is the same as the ideal calculation of the phasor sum of the A, B, C currents. Reference to A,B, C channels or phases in this appendix generally relate to the labeling of the Dranetz channels and for our computer program, which is not the same as the CNP designation.

The D-channel current probe at the Singleton substation was placed around all three phase CT output current conductors. Ideally those two arrangements should have the same D-channel current magnitude. However, because of some uncertainty on the "return conductor" the arrangement at Singleton is probably to be preferred. Data recorded at Singleton prior to March 31 provides some concern about what was being monitored on the common return conductor. In addition, some other data recently obtained on a different study indicates that problems may occur when attempting to use the CT circuit common return to monitor the residual current. However, for the time period of interest the D-channel probe direction at Singleton was opposite the direction of the A, B, C probes as it was when it was placed on the common 4th return conductor of the CT's. Therefore, the phase angle of the logged D-channel for Singleton is 180 degrees with respect to the phasor sum of the A, B, C currents. Therefore, the phase of the logged D-channel has been rotated by 180 degrees for presentation to be in-phase with the phasor sum of the A, B, C currents.

The CT ratio programmed into the Dranetz at Singleton was in error. The programmed value is 800, but after the tests were underway CNP identified that the actual CT ratio is 600 at Singleton. Therefore, all recorded Singleton current magnitudes were corrected by multiplying by a factor of 0.75 in an Excel spreadsheet after extracting the data from the Dranetz.

Both Substations (two circuits) Energized

Three-phase transmission line currents can be analyzed in terms of three "sequence" quantities, which are related to the actual phase currents by a mathematical transformation. The consideration of sequence currents is useful for analyzing coupling between power circuits and another nearby service such as a rail line or pipeline. The sequence representation permits separate consideration of the nominally balanced currents for each circuit (which are estimated depending on expected loads) and unbalanced currents (which are more difficult to estimate and account for). The three sequence components are called "positive, negative and zero" sequence. The positive and negative sequence quantities (currents) are "balanced", that is, they have the same magnitude in each phase conductor and are 120 degrees displaced in phase. However, for normal transmission lines, the negative sequence component is small with respect to the positive sequence component and can be generally ignored for coupling analysis.

For coupling analysis to railroad or pipelines, the magnetic field from the positive and negative (balanced) sequences fall-off much more rapidly with distance from the transmission line than does the zero sequence component, since the zero sequence component of current has the same magnitude and phase in each of the three phase conductors. The sum of the zero-sequence currents in all three phases of a transmission line circuit is called the residual current, that is, $I_r \underline{/\theta} = 3I_0 \underline{/\theta}$.

For a two-circuit three-phase transmission line, each circuit can have a residual current that is a phasor quantity, i.e. has a magnitude and phase. The two residual currents of a two circuit line can be treated as currents of a two conductor transmission line. That is, the two residual components (one for each circuit) can be decomposed into two components, a "common-mode" component that has the same current and phase in each three-phase circuit, and a "differential-mode" component that has the same magnitude but is 180 degrees different in each three-phase circuit. At distances that are significant with respect to the spacing between circuits, the LEF caused by the "differential-mode" residual component tends to cancel, while the LEF caused by the "common-mode" residual component of each circuit tends to add.

The measured transmission line current data show a "differential" component of residual current that is 180 degrees out of phase in the two circuits, along with a lower value of longitudinal or common-mode residual current that is in phase in each circuit. The net residual current (the sum of the two circuit common mode currents), along with the balanced positive-sequence current, appears to be most important for magnetic-field coupling to the rail system. The distinction between the common-mode and differential-mode components of the residual current is normally not made for including residual currents in the mitigation analysis. The normally used method for including double-circuit residual currents in the analysis considers the magnitude of the residual current in each circuit to be common mode, or in phase as a worst case, and thus may be overly conservative. This appendix identifies a net residual current that appears to be more appropriate, based on these measured data. The net residual current identified by these data and analyses is less than the individual circuit residual current and is approximately one half the residual current estimated by CNP and initial measurements made in 2008.

The residual current ($3I_0$) for a single circuit can be calculated using the measured magnitude and phase of the A,B,C current values in an appropriately outfitted substation. Alternatively, the residual current can be directly measured using a fourth current probe. The Dranetz 4400 permits logging of four current-probe channels. The fourth channel is called the D channel. The use of the D-channel current ideally provides a more direct and possibly more accurate procedure for evaluating the residual current than does calculating the residual current from measured magnitude and phase values of the three phase currents. The measurements reported in this appendix used the D channel in an attempt to directly measure the residual current of Ckt 74C at the Singleton substation and Ckt 75B at the Roans Prairie substation.

We have also calculated the residual current for each circuit from measured A,B,C currents in an Excel spreadsheet for comparison to the value obtained directly from the D-channel. The zero-sequence current (Io) is also calculated by the Dranetz software. Those values were multiplied by a factor of three in the Excel spreadsheet. The results of these three methods of determining "Residual Current" are shown in Figure 1 for Singleton and in Figure 2 for Roans Prairie for the time period when both circuits were energized. In both figures the D-channel measured values are shown as a red

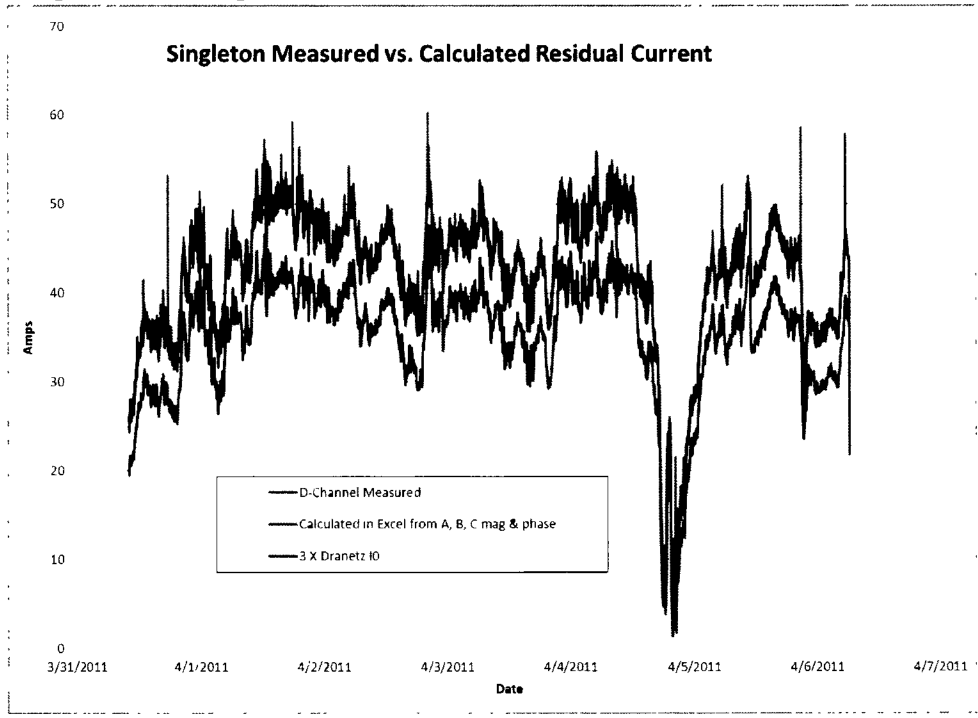

Figure 1. Singleton Residual Current Values.

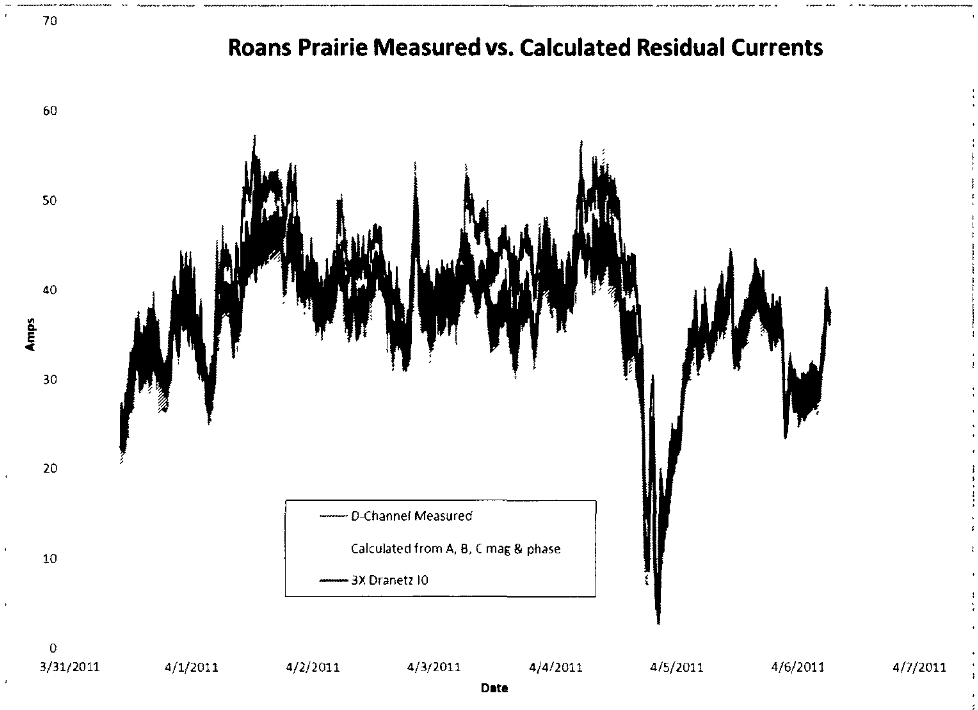

Figure 2. Roans Prairie Residual Current Values.

curve, while the two calculated values are shown as blue and green curves. For both figures, the two calculated residual current values (the green and blue curves) are in very good agreement, as would be expected. For Singleton, the calculated residual current values are about 25% higher than the D-channel measured values. We don't know the source of the error, but it appears to be systematic, not random. At Roans Prairie, the measured values tend to be somewhat higher than the calculated, but all three procedures are in better agreement than at Singleton and the offset does not seem so systematic. Thus, it appears reasonable to use the measured values of residual current for both substations for subsequent consideration. The D-channel measurement procedure used at Singleton should be the most reliable, but that gives the greatest difference from calculated. The D-channel measurement at Roans Prairie might be more prone to error (because of uncertainties in the return path), but those measurements agree better with the calculated (from A, B, C measured) values.

Figure 3 shows scatter plots of the measured circuit residual current as a percentage of I1 (nominally the average phase current) for both Singleton and Roans Prairie for the period when both circuits were energized. It is seen that the residual currents tend to become asymptotic to a nominal percentage as the load becomes higher. At the higher load current, the Roans Prairie circuit percentage residual is approximately twice the Singleton residual current, as a percentage of balanced current in the individual circuits. At lower values of current, the percent residual current becomes considerably higher.

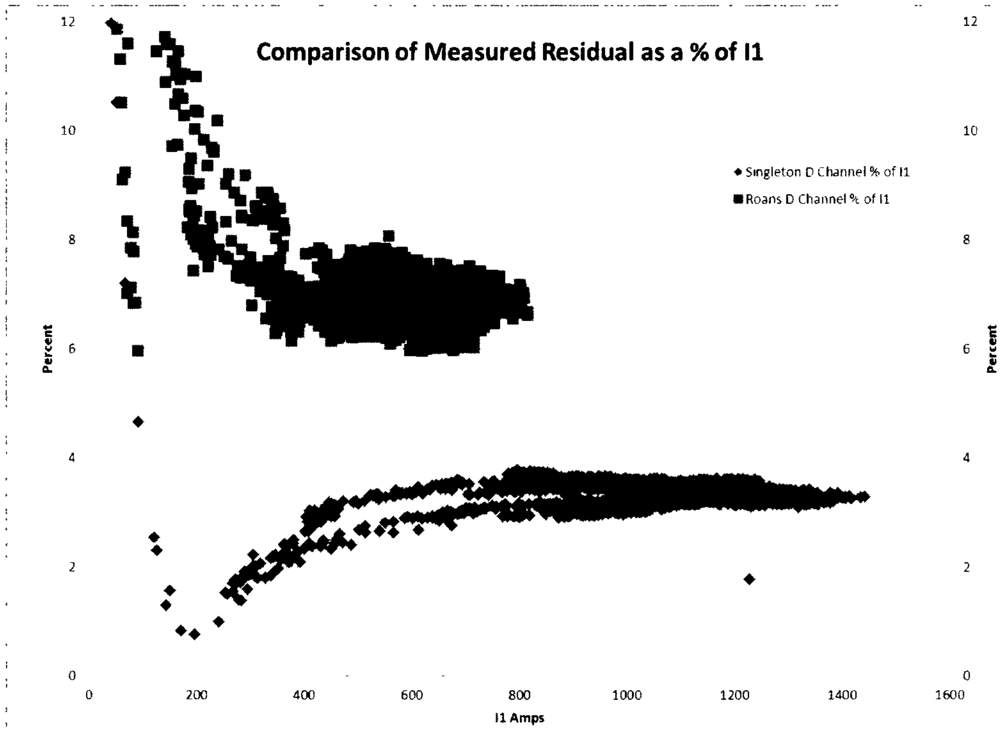

Figure 3. Residual Current as a Percent of I1.

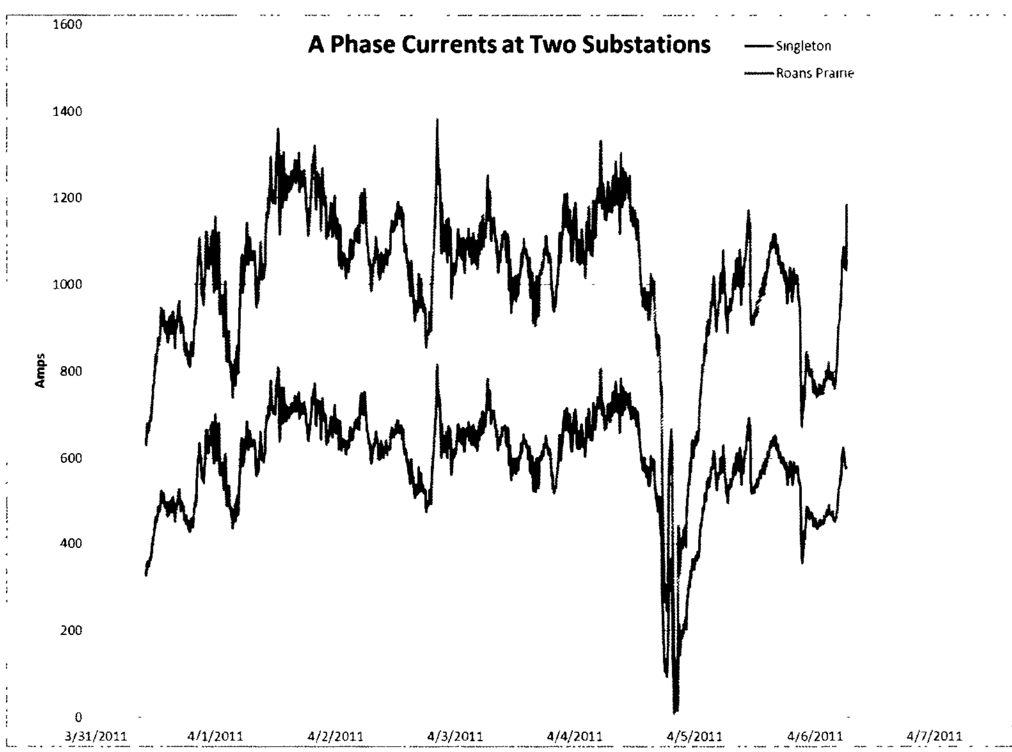

Figure 4. Reference-Phase Currents at Singleton and Roans Prairie.

Figure 4 shows the magnitude of one of the phase currents at each of the substations during the period when both circuits were energized. For most of the time, the Singleton current is approximately twice that of Roans Prairie. There is a period on late April 04, early April 05 that had quite low current at both substations. That period is primarily responsible for the higher values of percentage residual currents. We are primarily interested in the higher values of load current for modeling voltage coupling to the rail system, by extrapolating to "full load" conditions. We will, for this discussion, focus on the higher observed values of load current for attempting to assess trends in the residual currents. Therefore, for simplicity we will ignore the values during that period of depressed load.

Figure 5 shows the measured residual currents at both substations as a percent of I1, vs. I1 with the low-current period from 4/04/11 14:40 to 4/05/11 03:00 removed. Comparison of this graph with Figure 3 shows that the remaining data are relatively well behaved. The Roans data are reasonably clustered between 6 to 8%, while the Singleton data are more tightly clustered about approximately 3.5%. Although this plot indicates that the Roans percentage residual is consistently higher than for Singleton , Figure 4 shows that the I1 current is higher at Singleton.

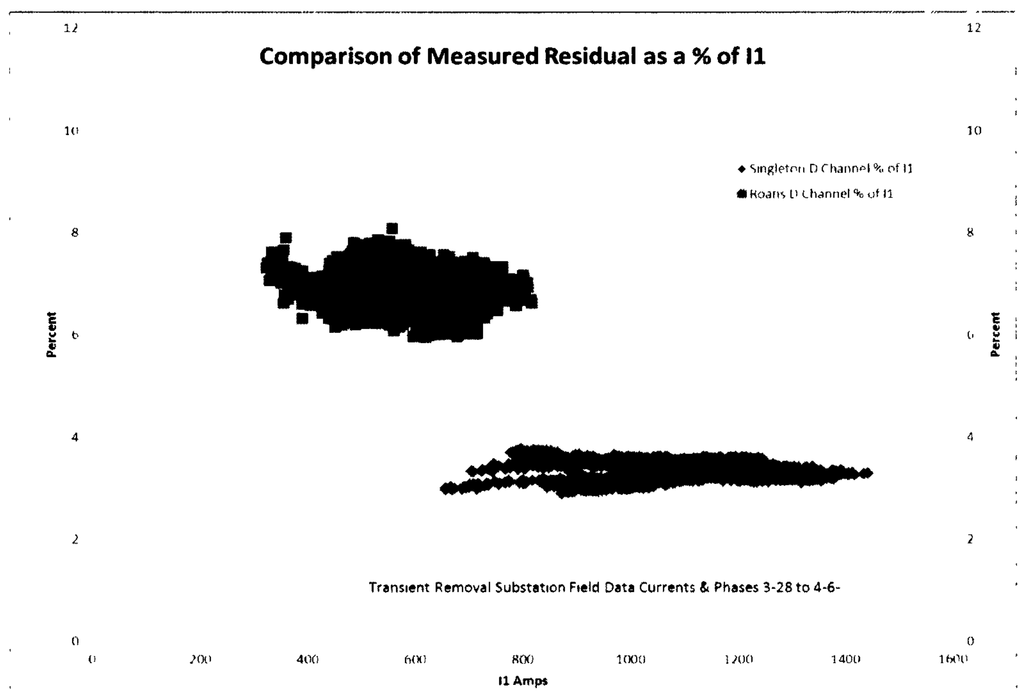

Figure 5. Measured Residual current % of Positive Sequence Current for Singleton & Roans.

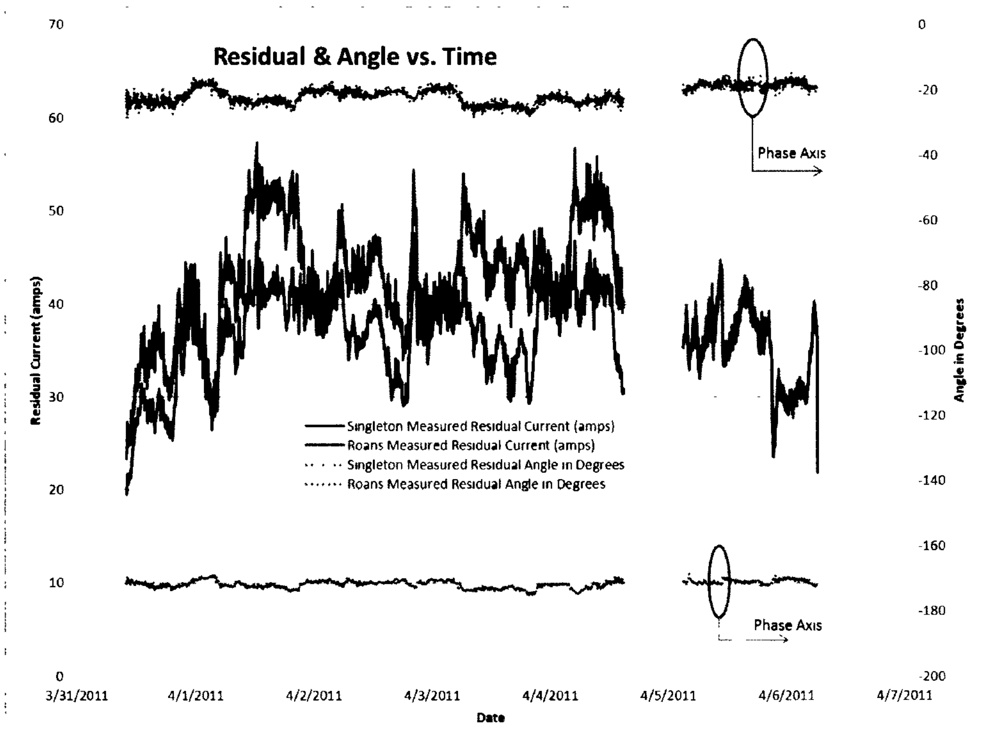

Figure 6. Residual Current Each Circuitand its Phase with reference to the phase of the Dranetz A-Phase Voltage.

Both the magnitude and phase of the residual currents are of interest for modeling and extrapolation to higher loading conditions. Figure 6 shows the residual current and the phase of the residual current for both Singleton (Ckt 74C) and Roans Prairie (Ckt 75B) for the period when both circuits are energized. For clarity, the low load segment of time has been eliminated from the data of Figure 6.

From Figure 5 it is seen that both residual currents tend to be nominally a constant percentage of the positive-sequence current. That is, the individual circuit residual currents tend to increase and decrease with the circuit load, as is shown in Figure 7, which plots the positive sequence and residual current magnitudes at Roans Prairie (on different axis).

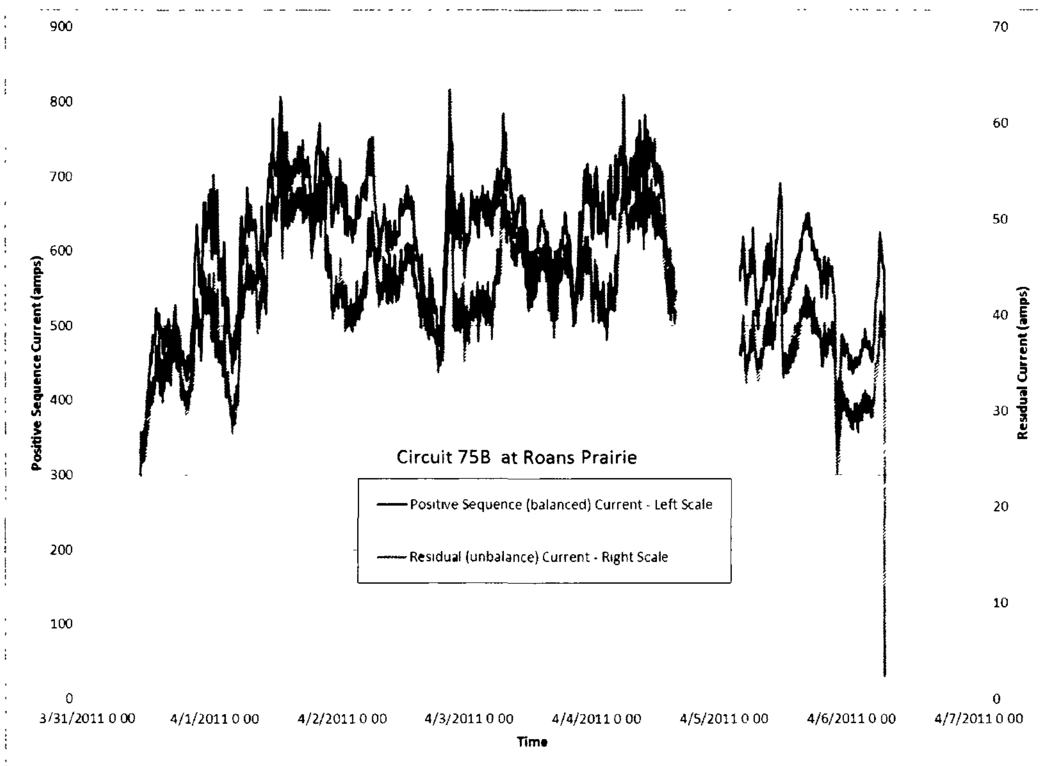

Figure 7. Balanced and Unbalanced Current on Circuit 75B vs Time

However, also of interest in Figure 6 is the fact that the residual currents in the two circuits tend to be approximately out of phase. The phase of the residual at Roans tends to be in the range of -20 degrees, while the phase of the residual at Singleton tends to be in the range of -170 degrees, both referenced to the A-phase voltage of each circuit. Thus, these data tend to suggest that the Longitudinal Electric Field (LEF)[8] caused by the residual currents of each circuit will tend to cancel, but not completely since they are not exactly the same magnitude and not exactly 180 degrees out of phase.

One Circuit out of Service

The above field data is with both circuits operating. We were fortunate that data was also obtained with one of the circuits (Roans Prairie) out of service from 4/07/11 to 4/12/11. That data is discussed below.

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[8] The LEF is the voltage per unit length that is induced into the rails by the current in the transmission line.

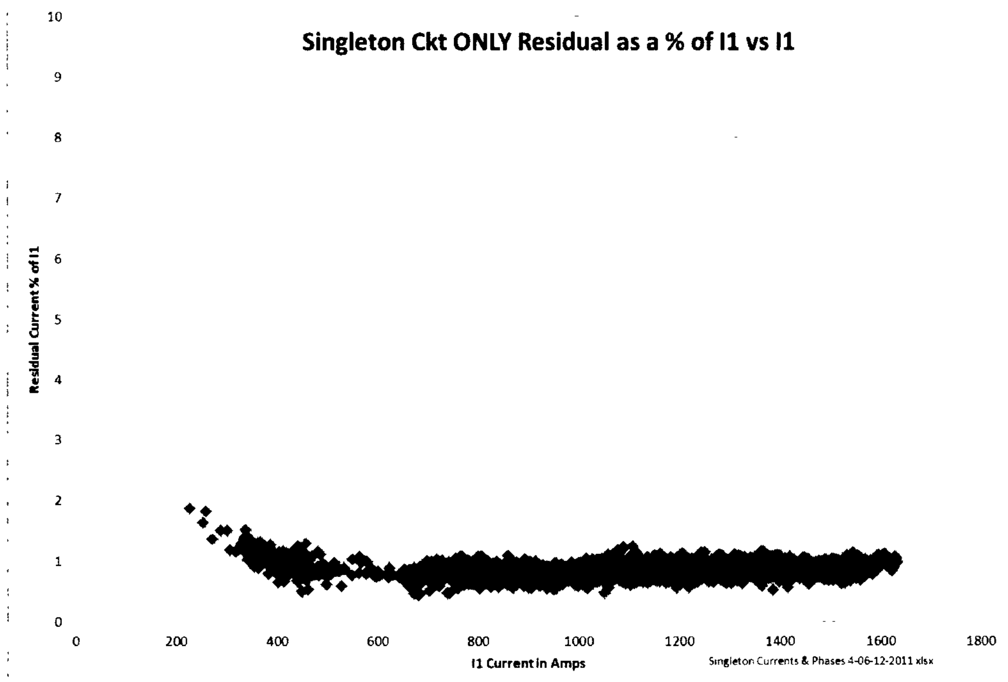


Figure 8. Residual Current at Singleton (as a % of I1) for Six-Day Period with Roans Prairie Out of Service.

For this discussion, the relevant data for this period is the Singleton circuit residual current as a percentage of the positive-sequence current, which is summarized in Figure 8. It is seen that for this period of time, the residual current is approximately 1% of the positive-sequence current, except when the current is less than about 300 amperes. Comparison to Figure 5, with both circuits "on", shows that the percentage residual current is significantly higher with both circuits energized. This is likely caused by magnetic-field coupling between the two mutually-coupled transmission circuits.

The current unbalance data obtained in the field is informative. The data shows that the percentage current unbalance for each circuit tends to be relatively constant with load, at least for currents above about 500 amperes, which is the primary case of interest.

However, with both circuits energized the percentage unbalance for the two circuits is not the same, with Roans being less current and higher % unbalance as in Figure 5. Most of the data with both circuits energized had a relatively constant ratio of current in the two circuits (Roans Current)/(Singleton Current)≈ 0.55. So we don't have a good data set for extrapolating to possible worst-case conditions with both circuits heavily loaded or for estimating for other ratios of current in the two circuits. When only one circuit is energized, the unbalance is less than with both circuits energized.

The data give rise to questions such as:

- how will the unbalance currents change as the Roans load current increases to be more equal to the Singleton load current?

- For that case, will the percentage Roans current unbalance decrease to be more like Singleton?
- Does the net residual current stay about the same in both circuits, but out of phase as suggested in Figure 6?

These questions are important for the compatibility analysis, since the preliminary mitigation analysis shows that the mitigation design is driven by the steady state condition with both circuits energized.

Our normal procedure for evaluating the field effect of the unbalance currents uses measured or estimated percentage unbalance for each circuit and assumes that the phase of the unbalance current is unknown, which is generally the case. Therefore, as a worst-case the phase of the unbalance (residual) currents are assumed to be independent of the balanced currents and in-phase for each circuit. The field caused by the residual currents is, as a worst case, considered to be possibly in-phase with the field that is caused by the balanced components of current. Thus for our normal mitigation design procedure, the modeled field (LEF) caused by the residual current in each circuit is algebraically added to the LEF caused by the balanced current in both circuits to obtain the total exciting field, based on lack of definitive information on the phases of the residual current in the individual circuits.

That procedure may be too worst case, at least for this exposure, (since we tend to add the two unbalance contributions) and may result in additional mitigation complexity and costs. It seems worthwhile to investigate if the measured data discussed above can help reduce the assumptions used for modeling the effects of unbalance with double-circuit transmission lines.

In an attempt to answer these important questions, a simple model of the power line has been analyzed.

Unbalance for Simple Transmission Line Model

Existing Phase Arrangement

A simple model of has been made to approximate the 74 (Singleton) and 75 (Roans Prairie) circuits during the measurement period for estimating the influence of line loading on the residual current in each circuit. The simple model has two segments. A double-circuit Delta is modeled with the existing phase configuration. That segment is 41 miles long to simulate the region from the Singleton and Roans substations to just north of Tomball, where the lines become double-circuit vertical. The second segment is double-circuit vertical ABC top-bottom for both circuits to simulate the line north of the King substation. Nominal load drops were simulated at Tomball and at Kuykendahl. The two circuits are connected to a common bus only at King. The circuits were driven by ideal 345kV balanced three-phase voltage sources at the location of Singleton and Roans and King. The line current flow was controlled by the phase shift of the Singleton and Roans voltage sources relative to the King source, which is the procedure used in Ref (1) (Hesse, 1966). The OHSW's were included in the model.

Figure 9 compares the measured and model-calculated residual currents in the two circuits versus the ratio of balanced current (positive sequence I1) at Roans to Singleton, for a nominally constant full load I1 (positive-sequence) current at Singleton(3600A). The individual circuit calculated residual current (red and blue lines) are expressed as a percentage of the circuit positive sequence current. It is seen that as the load current in the Roans line becomes less relative to the Singleton line, the percentage unbalance of the Roans line becomes higher, while the unbalance of the Singleton line remains relatively constant.

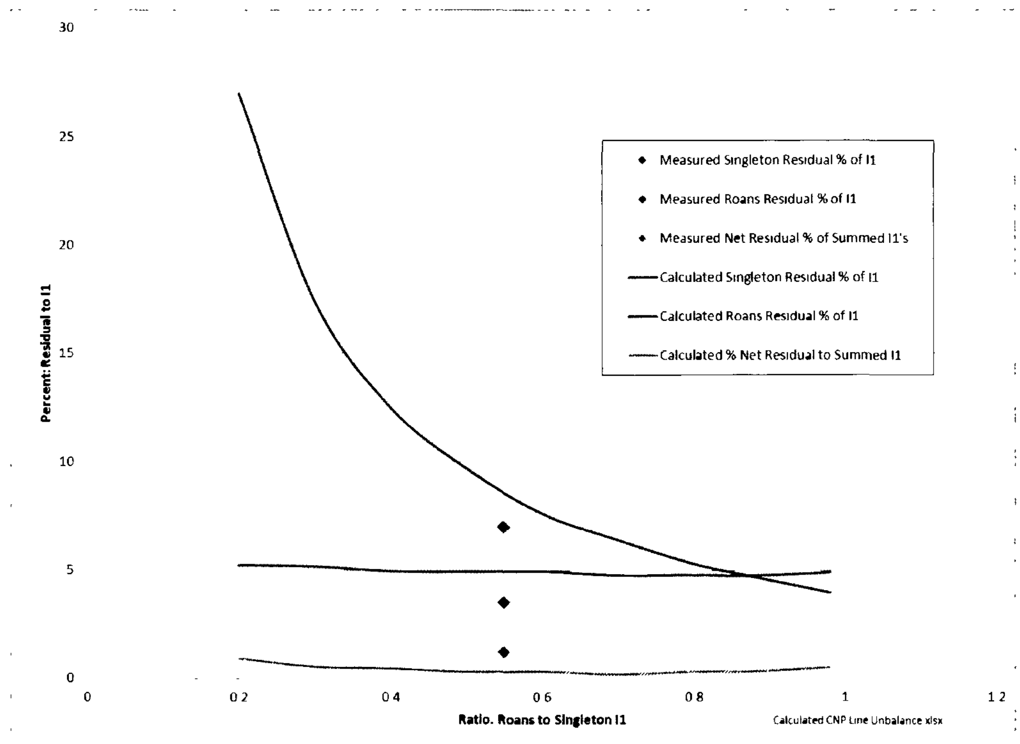


Figure 9. Comparison of Calculated and Measured Transmission Line Residual Currents.

The green line is the calculated *net residual current* as a percentage of the sum of the two I1 currents. The calculated *net residual current* is the phasor sum of the calculated residual current in each circuit and is the unbalance component of current that will contribute to the LEF. That is, the field from the two individual residual currents will tend to cancel because they are nearly out-of-phase. The *net residual current* is the unbalance component of current that would be measured if a single current probe could be placed around *both* circuits. That is, the *net residual current* is the sum of the common-mode component of residual current in each circuit. The net residual current is of importance for compatibility assessment and mitigation design. The analyses for Figure 9 used a relatively high, nominally constant, value of current at Singleton (approximately 3600A). Other preliminary analysis indicates that the results are rather independent of the actual current values, but depend on the ratio of currents as displayed in the figure.

Also shown in Figure 9 are discrete points which are nominally the average of measured data from Figure 5. Those measurements were made at lower currents than assumed for the analysis of Figure 9, but as noted above, the calculated results appear to be not strongly dependent on the current magnitude, i.e. the analysis is linear. The measured values are somewhat different than the calculated values, possibly because of the many simplifying assumptions for the analysis. However, the trends tend to be similar, principally that the net residual current is significantly less than the sum of the individual circuit residual currents.

The zero sequence or residual characteristics of a double circuit transmission line can be characterized by two components:

- a net residual current (sum of the "common mode" residual currents that is equally divided between the two circuits). The net residual is the phasor sum of the 3Io component for each circuit.
- a "differential" residual current, which the same magnitude, but 180 degrees out of phase in each circuit.

This is illustrated from the measurements on Ckt 74 and 75. Figure 10 shows both the net (common mode sum) residual and the differential residual current for that same data.

> *A brief definition of terms is appropriate. Let the phasor residual currents in the two circuits be defined as i_1 and i_2. The "net residual" current is ($i_1 + i_2$), one half of which (generally called the common mode current) flows in each circuit. We prefer to identify the "net residual", which is the sum of the individual circuit common mode (3Io) currents, since the net residual is the total earth return component that couples to adjacent victim circuits. The "differential" residual current is equal in each circuit but is 180 degrees out of phase in each circuit. That is, the differential residual current flows in opposite directions in the two circuits and is given by ($i_1 - i_2$)/2.*[9]

From Figure 10, the net residual current for these measured data is relatively constant at an average of 1.22% of the summed I1 currents with a maximum value of 1.63%. The "differential" residual current has an average of 2.2% and a maximum of 2.4%, for the range of measured I1's, also from Figure 10 with both circuits energized. Considering just the maximum value of each gives a ratio of the maximum measured residual current (differential)/(net) ≈ 1.5.

Alternative Phasing Arrangement Considerations

As discussed in Appendix A an alternative phasing arrangement results in lower LEF in the region of the tracks from the balanced component of currents in the two circuits than the existing phasing arrangement. Figure 11 shows the existing and proposed alternative phasing arrangements.

We only have measurements for the existing phasing arrangement, which results in relatively low net residual current as is shown in Figure 9 and Figure 10. Therefore, it was of interest to assess if the use of the alternative phasing arrangement should also be expected to give low net residual current.

The model that was used to develop Figure 9 was used to calculate the residual currents for the alternative phasing arrangement. The alternative phasing model assumes that the phasing change shown in Figure 11 is made for Ckt 74 between Singleton and Tomball. The model results are shown in Figure 12, which has the same format as Figure 9. Comparison of the calculated net residual current in Figure 9 and Figure 12, shows that the calculated net residual current is higher for the alternative phasing

[9] Clayton Paul,"Introduction to Electromagnetic Compatibility", John Wiley & Sons, Inc. 2006, pp348.

arrangement of Figure 12. However, the calculated net residual current in Figure 12 is less than 3% of the sum of the positive sequence currents from the two circuits, which means an equivalent net 3Io of 1.5% of the sum of the positive sequence currents flows in each circuit.

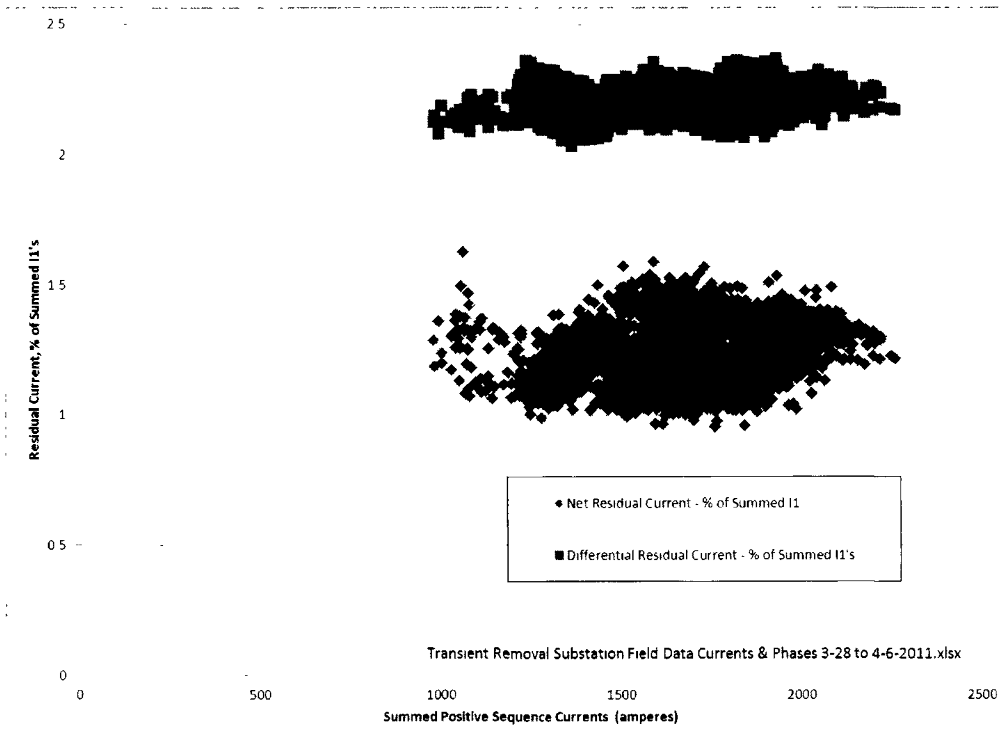
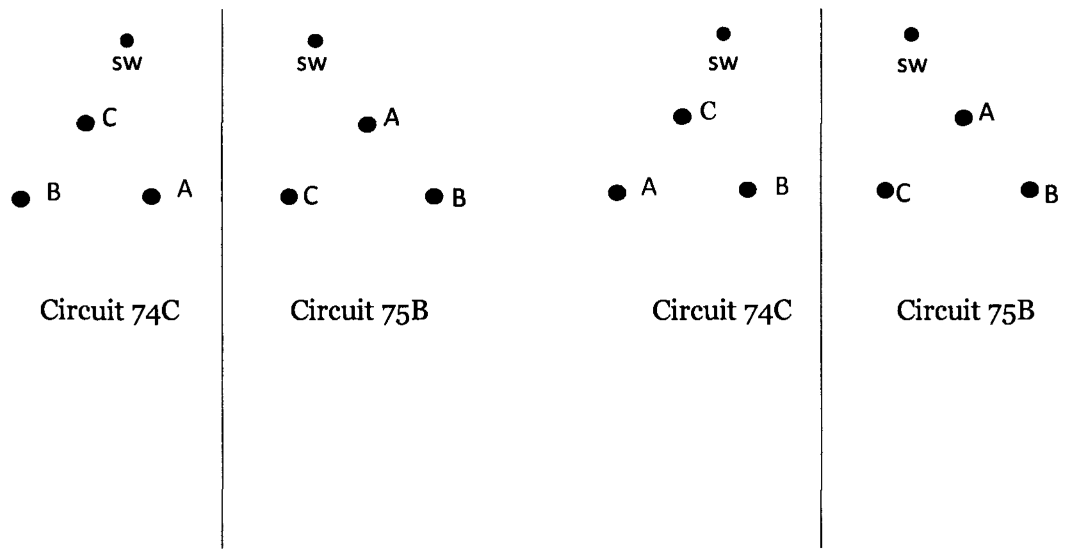


Figure 10. Differential and Net Residual Current from Measurements on 74 and 75 circuits.



EXISTING CONFIGURATION **ALTERNATIVE CONFIGURATION**

Figure 11. Phasing Arrangements for the two CNP Circuits (Looking North in Exposure Region).

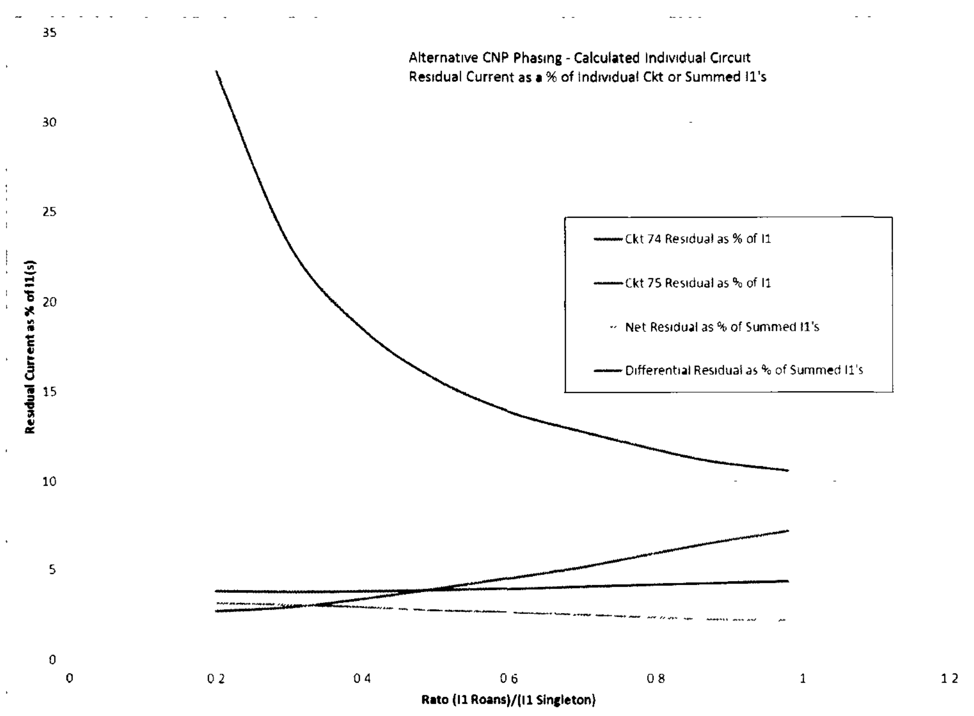


Figure 12. Calculated Transmission Line Residual Currents for Alternative Phasing, Using Simple Model.

Quantitative Comparison of Net Residual with Original Mitigation Design Assumptions.

The mitigation design Alternatives A and B use residual current of approximately 7% for each circuit based on:

- data obtained from a field test in June 2008.
- An estimate ($I_0 \approx 2.4\%$ or $3I_0 \approx 7.2\%$ residual) provided by CNP at the start of this investigation.

The normal mitigation analysis assumes that the individual circuit residual currents may add in phase as a worst case. The maximum load currents to be used for the design are 3672A for the 74 circuit and 2862A for the 75 circuit. Those assumptions are equivalent to a net residual current of 7.2% of the summed positive sequence currents.

From Figure 10 the maximum net residual current from the measured data is 1.63%, (of the summed I_1's) for the existing phase arrangement. From Figure 12, the calculated net residual current estimate for the alternative phasing arrangement is less than 3% of the summed I_1's. Thus, the conservative procedures that are being used for the Mitigation Alternatives A and B of the main text may be overestimating the net residual current by approximately a factor of two for the alternative phase arrangement. The Mitigation Alternative C, described in the main text attempts to correct for this overly conservative approach by considering the factors outlined in this appendix. That Mitigation Alternative uses a net residual current of 4% of the summed I_1's. which is nominally equivalent to each circuit having a residual of 4% of that circuit I_1.

Induced Rail Voltage - Field Measurements

Rail to ground voltages were logged using Dranetz 4400's during the time that the substation currents were measured. All Dranetz times were set to be within a few seconds of each other, so the rail and power system data can be analyzed using a common time base. The following is a summary of the results of our data review.

Figure 13 Shows a time plot of the voltage across one of the rail insulated joints (green line, right scale) and the I_1 currents at Singleton (blue curve, left scale) and Roans Prairie (red line, left scale). The general correlation among the curves is obvious. However, the rail voltage has numerous short duration transients that are assumed to be related to train movements, although those events have not been investigated. Those transients prevent a reasonable correlation analysis. Therefore, we have used a several period moving average to smooth the IJ voltage data. The resultant smoothed IJ voltage is shown as the purple curve in Figure 13. The smoothed rail IJ voltages have been used for developing Figure 14 and Figure 15 which are discussed below.

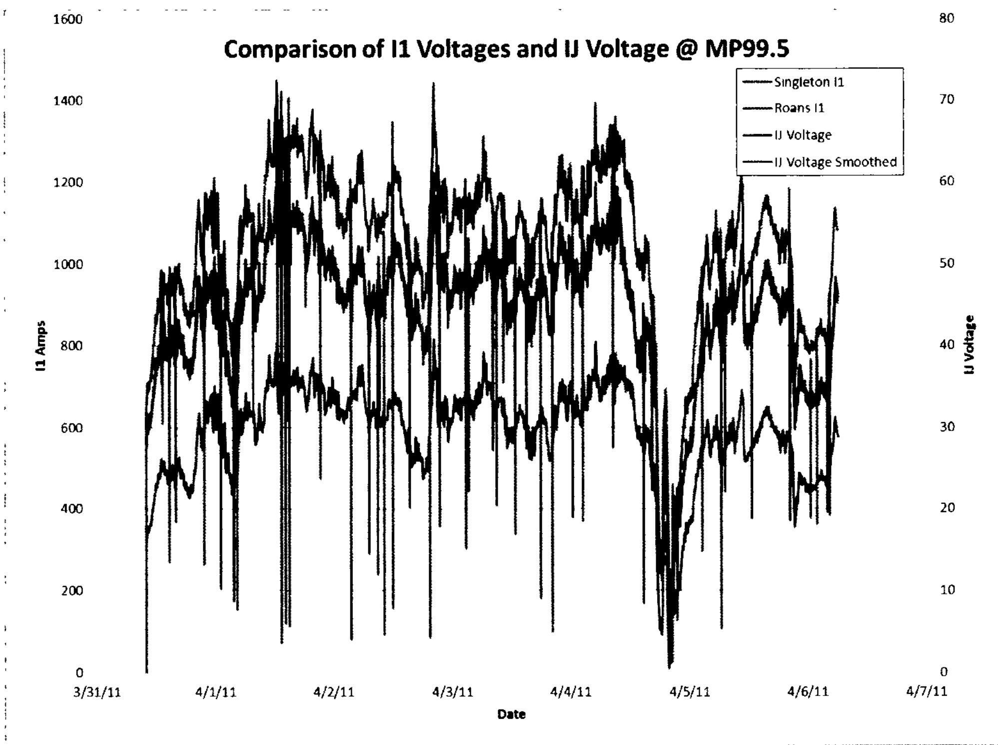


Figure 13. Plot of Measured IJ Voltage and Power Current.

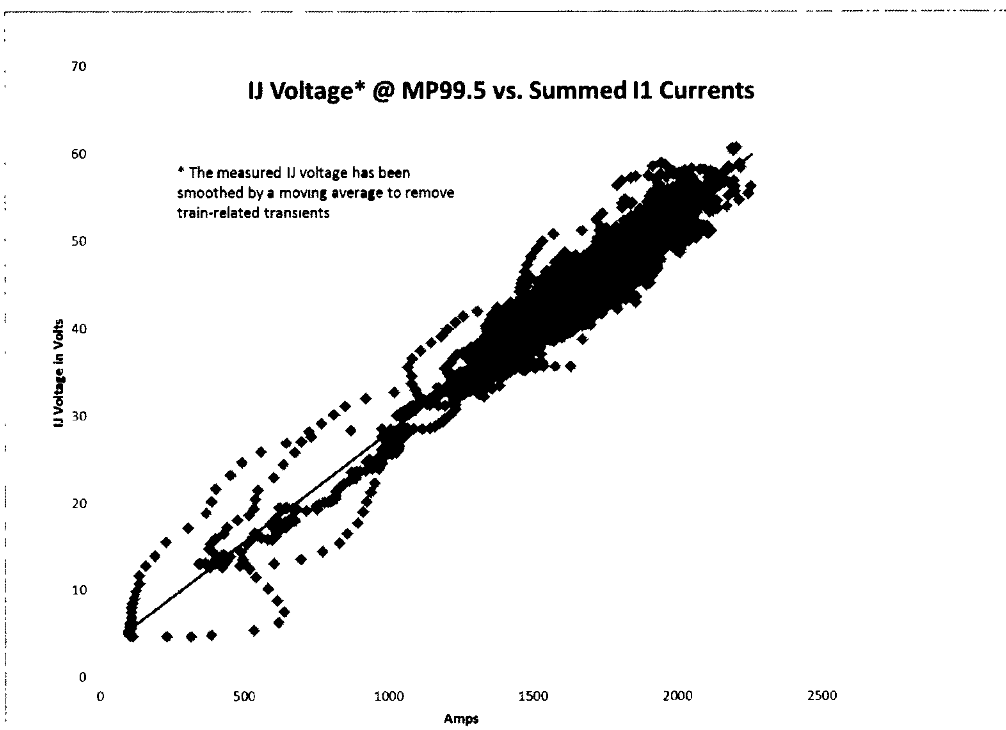


Figure 14. MP 99.5 Measured IJ Voltage vs Summed (both circuit) Positive-Sequence Current

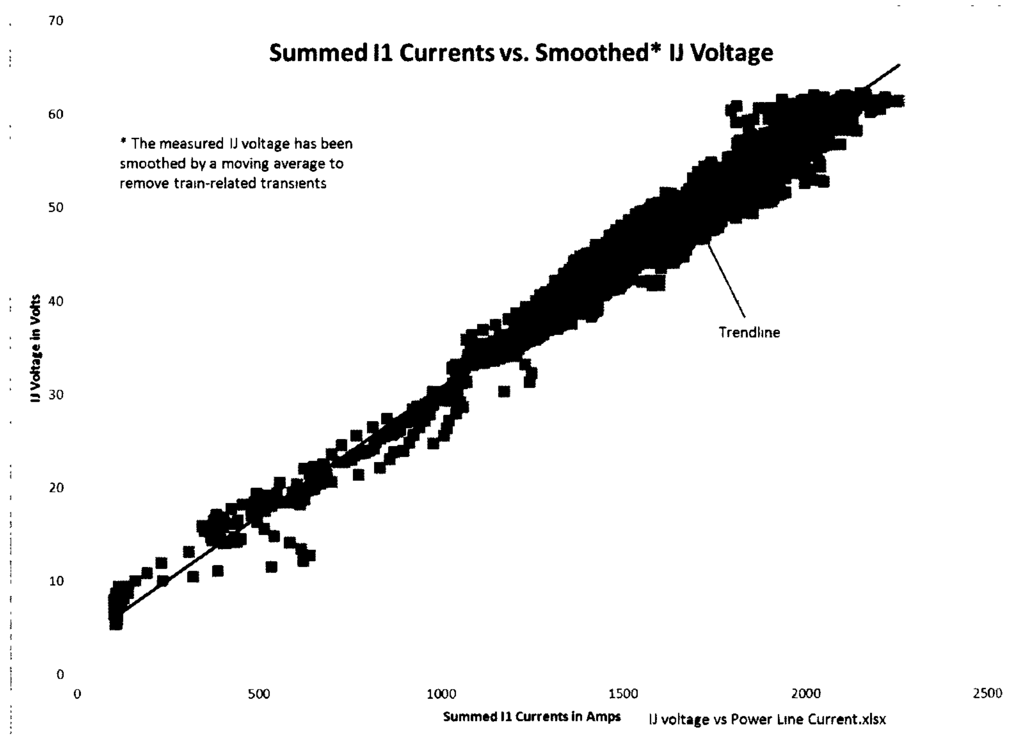


Figure 15. MP 101.5 Measured IJ Voltage vs Summed (both circuit) Positive-Sequence Current.

Figure 14 and Figure 15 show scatter plots of the smoothed measured track IJ voltage versus the summed measured positive-sequence current of the two transmission circuits for track measurements at MP 99.5 and MP 101.5 respectively. The positive correlation in the plots unquestionably establishes a causal relationship, although the data spread is somewhat loose particularly in Figure 14. The data spread may be contributed to by inadequate filtering of the IJ voltage. The cause of the data spread has not been further investigated. For example in Figure 14 at summed currents less than 1kA, the IJ voltage range is in the range of 2:1, but improves for higher currents.

Measured Rail Voltage Comparison with Model

The following paragraphs describe the comparison of field measured transmission line and rail data with model calculations. The procedure used was to select representative times using Figure 13. That figure shows the time plot of measured voltage across one of the rail IJ's at MP 99.5 along with the time plot of positive sequence (I1) current for each circuit. The time data are recorded at two minute increments. The clocks of the Dranetz units were synchronized to be within seconds of each other. The values shown are the Dranetz averaged value for each quantity over each two-minute interval. Two representative time periods have been selected for analysis. The first is at a time with relatively high values of rail voltage. The second is at a time with relatively low values of rail voltage as shown in Figure 13.

Once we selected the times, we used the relevant Dranetz data to identify the values of current and voltage at those times. For comparing measured data to a model, we used a model file developed during the preliminary mitigation investigation with values, locations, analysis branches, ballast and soil resistivity the same.

The table below summarizes the measurement and analysis results (Table 1). The table is in two colors, one for each time snapshot of comparison. The first time, for higher rail voltage, is for 4/01/11 at 15:20 hour (in blue). The second time, for lower rail voltage, is for 4/06/11 at 03:30 hour.

Each color section has the same categories of information. The power system information is presented for Ckt 74 and 75 in the upper half of each colored section. Column 1 and 2 show the A-phase current magnitude and phase respectively. The other phase currents are shown in successive columns. The railroad information is at MP 99.5 and 101.5 and is shown in the lower half of each colored section. For this analysis we chose to use the voltage across one of the insulated joints at each signal location. The track-connected Dranetz provides an output of the voltage between the A and C channels, which is the voltage across one of the insulated joints. Those measured values of IJ voltage are shown in labeled column 2 (in the lower half of each colored section) for both times. For the first time snapshot, the IJ voltages at the two locations were in the 55-61 volt range, while for the second time snapshot the IJ voltages were in the 35-38 volt range.

The next several columns (in the lower half of each colored section) provide calculated IJ voltages at those same MP locations, using different procedures as described below. The voltage is calculated across each IJ of the pair at a location. Those IJ voltages in each rail generally differ by about one volt. The calculated IJ values shown in the table are the average of the two IJ voltages at each location of interest. The calculated IJ voltages in labeled column 3 used the measured magnitude and phase values of the A, B, C currents at each substation at each time of interest as input to the computer program. Those calculations agree with the measured rail voltages within a few volts.

The calculated IJ voltages in labeled column 4 used the measured magnitude and phase values of the D (residual channel) and the positive sequence current I1 calculated from the measured A, B, C currents at each substation at each time of interest as input to the computer program. The negative sequence component is ignored. We feel that this calculation procedure is most accurate. Those calculations agree with the measured rail voltages within a volt or less.

Table 1. Summary of Measurement and Analysis Results

Column #	1	2	3	4	5	6	7	8	9	10	11	12
		Measured Data of	4/1/2011 18:28			** ID values based on Measured D-channel amplitude and phase.						
	Ia (mag)	Ia (phase deg)	Ib (mag)	Ib (phase deg)	Ic (mag)	Ic (phase deg)	ID (mag)**	ID (phase deg)**	I1 (mag)*	I1 (phase deg)*	net ID (mag)	net ID (phase)
Singleton Ckt 74	1254	3.2	1335	-117.6	1384	121.35	14.17	-172	1304	2	4.447[illegible]	-77.1179[illegible]
Reans Prairie Ckt 78	725.3	4.46	716.4	-118.7	691	116.8	17.86	-82.7	720.77	0.86		
		Measured IJ V	Calculated avg IJ V based on Meas. Ia,b,c	Calculated avg IJ V based on Meas. I0, I1	Calculated avg IJ V based on I1 & calc Net Ir	Calculated avg IJ V Use I1's only	Calculated avg IJ V Only ckt IDs in phase	Calculated avg IJ V Add Col 6 & 7				
Analysis Node 78	MP 88.5	86.39	80.1	85.8	85.25	40.89	41.2	84.75				
Analysis Node 81	MP 101.5	81.17	86.76	80.1	81.18	42.8	44.7	88.2				
		Measured Data of	4/8/2011 3:30									
	Ia (mag)	Ia (phase)	Ib (mag)	Ib (phase)	Ic (mag)	Ic (phase)	ID (mag)	ID (phase)	I1 (mag)	I1 (phase)	net ID (mag)	net ID (phase)
Singleton Ckt 74	787.29	2.77	806.86	-117.84	847.46	120.72	16.29	-176.76	[illegible]	2.08	2.481846154	-86.247[illegible]
Reans Prairie Ckt 78	[illegible]	3.7	481.4	-116.1	440.88	118.74	8.36	-46.7	468.34	1.17		
		Measured IJ V	Calculated V based on Meas. Ia,b,c	Calculated V based on Meas. I0, I1	Calculated avg IJ V based on I1 & calc Net Ir	Calculated avg IJ V Use I1's only	Calculated avg IJ V Only ckt IDs in phase	Calculated avg IJ V Add Col 6 & 7				
Analysis Node 78	MP 88.5	34.88	32.16	34.86	28.7	27.85	34.7	64.35				
Analysis Node 81	MP 101.5	37.07	38.1	37.6	37.3	60.7	28	88.7				

Notes:

The calculated IJ voltages in labeled column 5 used the calculated magnitude and phase values of the net residual current with ½ applied to each circuit and the positive sequence current I1 calculated from the measured A, B, C currents at each substation at each time of interest. Those calculations agree with the measured rail voltages within a volt or less.

The calculated IJ voltages in labeled column 6 used only the positive sequence current I1 calculated from the measured A, B, C currents at each substation at each time of interest. Those calculated IJ voltages are approximately 20% less than the measured values.

The calculated IJ voltages in labeled column 7 used only the measured D channel magnitude for each circuit, assumed to be in phase with each other as a worst case.

The calculated IJ voltages in labeled column 8 are the algebraic sum of the of the positive sequence induced voltage of column 6 and the residual induced voltage of column 7, as would have to be done if good knowledge of the residual current phases were not available, which is the normal method that we use. Those results are in the range of 1.5 times the measured voltages. The individual circuit residual currents are approximately 3.5% of that circuit I1. The Mitigation A and B designs have used nominally 7% single circuit residual currents, based on the data from 2008 and CNP estimates, and basically the same procedure as for column 8. The 2008 data was obtained for a yet different phase arrangement of the two circuits, which existed prior to the phase arrangement that existed for these measurements. Thus, that data may not be suitable for the existing or alternative phasing arrangement.

Other comparisons can be made, but the above comparisons show that the basic model of the exposure that was used for mitigation design analysis is quite accurate relative to the conditions that existed when the field data were collected, if the proper power currents are used for the analysis.

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
2019 CEHE RATE CASE
DOCKET 49421-SOAH DOCKET NO. 473-19-3864

PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-21

QUESTION:

For the project listed under Project Number HLP/00/0922 and described in the WP RMP-2 Capital Project List Summaries (years 2013-2014) "Line clearance corrections between transmission and distribution facilities on Ckt 05 Sharpstown-Sharpstown tap" (and also found in the 'WP RMP-2 Capital Project List Detail' spreadsheets for these years):

a. When were the facilities associated with this placed into service?

b. What dollar amount, if any, was incurred during the rebuilding, reconductoring, or upgrading of existing electric facilities?

c. Please elaborate on why these corrections were necessary.

d. Why does CenterPoint believe this work should be capitalized instead of treated as an operations or maintenance expense?

ANSWER:

For the project listed under Project Number HLP/00/0922 and described in the WP RMP-2 Capital Project List Summaries (years 2013-2014) "Line clearance corrections between transmission and distribution facilities on Ckt 05 Sharpstown-Sharpstown tap", see following responses:

a. The facilities were originally installed in 1959.
b. The cost of the line clearance correction was $4,579,898.
c. These corrections were necessary to upgrade these facilities to increase line capacity. This was identified by system modeling studies. To achieve the facilities upgrade, CEHE also had to also address NESC line clearance and wind loading requirements.
d. This work should be capitalized because 1.44 miles of wood poles (w/associated hardware and conductor) were replaced with steel poles (w/associated hardware and conductor).

SPONSOR (PREPARER):
Randal Pryor/Martin Narendorf (Randal Pryor/Martin Narendorf)

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
2019 CEHE RATE CASE
DOCKET 49421-SOAH DOCKET NO. 473-19-3864

PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-22

QUESTION:

For the project listed under Project Number HLP/00/1055 and described in the WP RMP-2 Capital Project List Summaries (years 2014-2017) as "'Distribution line clearance corrections between transmission and distribution facilities to meet National Electrical Safety Code (NESC) requirements" (and also found in the 'WP RMP-2 Capital Project List Detail' spreadsheets for these years).

a. When were the associated transmission and distribution lines placed into service?

b. What dollar amount, if any, was incurred during the rebuilding, reconductoring, or upgrading of existing electric facilities?

c. Please elaborate on why these corrections were necessary and explain how CenterPoint become aware of the need to correct this clearance.

d. Did a change to NESC requirements necessitate this work? Please provide supporting documentation as needed.

e. Why does CenterPoint believe this work should be capitalized instead of treated as an operation or maintenance expense?

ANSWER:

For the project listed under Project Number HLP/00/1055 and described in the WP RMP-2 Capital Project List Summaries (years 2014-2017) as "'Distribution line clearance corrections between transmission and distribution facilities to meet National Electrical Safety Code (NESC) requirements", see following responses:

a. Project 1055 represents CEHE's Lidar based Transmission Line Clearance Program. CEHE performs Lidar surveys on approximately 20% of the transmission system each year to identify and correct NESC transmission line clearance issues. During the 2014-2017 time-period, 204 transmission line clearance issues, involving 158 distribution circuits and 69 transmission circuits, were addressed by modifications to distribution facilities. In addition, 85 transmission clearance issues were resolved by modifications to 55 transmission circuits. Information on the in-service dates for the transmission lines and distribution lines is not readily available.

b. Between 2014 and 2017, a total of $19,376,931 was spent on this project.

c. CEHE's Transmission Line Clearance Program (1055) utilizes LIDAR technology to determine clearances as compared to the NESC standard at the time of survey. Approximately 20% of the transmission system is surveyed each year. Clearance corrections are addressed by modifications to transmission facilities, distribution facilities, or both.

d. No. This work is not a result of any changes to NESC requirements.

e. This work should be capitalized because the modifications included the replacement of poles, pole hardware, conductors, and other capital facilities.

SPONSOR (PREPARER):
Randal Pryor/Martin Narendorf (Randal Pryor/Martin Narendorf)

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
2019 CEHE RATE CASE
DOCKET 49421-SOAH DOCKET NO. 473-19-3864

PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-23

QUESTION:

Please provide any CenterPoint Policies or documents related to proactive replacement of capital items.

ANSWER:

See attachment PUC06-23 Proactive Replacement of Capital Items.docx for the policies or guidelines related to the proactive replacement of capital items related to the Pole Maintenance Program, the Cable Life Extension Program, the Pole Top Switch Inspection Program, the Infra-red Inspection Program, the Hot Fuse Program, the Feeder Inspection Program, the Root Cause Analysis Program for 10% Circuits, Major Underground, Personal Computers, Fleet, Telecommunications, Streetlights, Substation Asset Management Strategy, and Transmission Line Assessment.

SPONSOR (PREPARER):
Randal Pryor/Martin Narendorf (Randal Pryor/Martin Narendorf)

RESPONSIVE DOCUMENTS:
PUC06-23 Proactive Replacement of Capital Items.docx

PUC 6-23 Proactive Replacement of Capital Items.docx

Policies or Guidelines Related to Proactive Replacement of Capital Items

Pole Maintenance Program

The criteria for Pole Bracing (Reinforceable Pole) is the reject pole must be sound above and below the ground line area and can support a steel truss to reinforce a damaged ground line section. Reinforceable candidates must have no substantial decay below the excavated area and a minimum sound outer shell of 2" at 26" above the ground and 4" shell at 6'0". No poles that are less than class 2 and hold major equipment (pole top switch, regulator, recloser, IGSD). No 3 phase terminal poles, No double stack poles, No leaning poles 5% or greater. No poles holding 3-250 KVA transformers (or larger) that are smaller than class H2. No freeway, river, railroad or waterway crossings. No poles with a pole top extension.

Any reject pole that fails to meet the criteria for pole bracing is replaced.

Cable Life Extension Program

CEHE has developed a SAP HANNA platform predictive model that uses the following criteria: age, outages, high water outages, length of cable to determine a loop health score. Loops with higher health scores are candidates for proactive assessment in the Cable Life Extension Program. These loops are assessed using a partial discharge at operating voltage, 1.3, and 1.5 times the operating voltage, and providing results of different levels ranging from guarantee, pass or replace. During the assessment, there is also an on-site review of the transformers and terminations. Once the failed cables are identified, work orders are prepared for span replacements, as well as other equipment, transformers or terminators, that needs to be replaced.
This process only replaces equipment and cables that are identified as needed vs all assets on the loop.

Pole Top Switch Inspection Program

CEHE inspects pole top switches to ensure correct operation during service restoration events. The inspection program identifies switches to inspect based on age and reliability impact. During inspection, crews operate the switches, provide maintenance and make minor repairs. If the switch needs replacement, a follow-up order is created. The inspection program will result in O&M expenses and capital improvements.

Infrared Inspection Program, Hot Fuse Program, Feeder Inspection Program and Root Cause Analysis Program for 10% Circuits

All of these programs are designed to proactively identify and resolve reliability problems on the overhead distribution system. The resolution will often result in the replacement of a capital item.
Infra-red inspections are performed on an eight-year cycle. Seventy benchmark circuits, that are representative of the overall CEHE system, are inspected every two years to ensure that

the eight-year cycle is adequate to achieve the desired reliability results. If a circuit is identified as a repeating 10% circuit, meaning it's in the top 10% for SAIDI and SAIFI minutes, or a 300% circuit, meaning its SAIDI and SAIFI minutes are three times higher than the average circuit, then it is advanced on the infra-red schedule to the current year. This additional focus on the circuits with the highest SAIDI and SAIFI measurements are done to address performance issues. Also, circuits that are heavily loaded (greater than 500 amps) are inspected, as data has proven a higher failure rate of equipment when subjected to higher load.

The Hot Fuse Program identifies line and transformer fuses that have experienced recurring outages. On a daily basis, fuses are identified and within approximately four weeks, corrective action is identified. There are two hot fuse criteria: (1) recurring hot fuse – a fuse that has had a minimum of three outages within a 90-day period, and (2) ultra hot fuse – a fuse that has had a minimum of three outages within a 30-day period.

The Company's Feeder Inspection Program is a proactive program to inspect distribution feeders and laterals, on a periodic basis to identify and correct issues found with the condition of the feeder that could impact the reliable operation of the feeder.

The Root Cause Analysis Program analyzes circuits that the Company projects will not perform as well as desired under the SAIDI and SAIFI metrics. A detailed evaluation of a circuit's outages for the current year is conducted. From this analysis, a recommendation and action plan is generated to address circuit issues. CenterPoint Houston uses outage causes, outage location, outage frequency, customer outage minutes, and the results of a field inspection to develop an action plan that can include a number of possible recommendations to address the root cause of the outages.

Major Underground

Proactive Major Underground equipment replacement includes leaking or damaged transformers. It also includes replacement of switches, breakers, interrupters or other equipment that is obsolete with no available replacement parts and a history of misoperations or failures. Cable replacement is based on cable type and age. All butyl and lead covered cable that is well beyond 30 years old is being proactively replaced because of increased failure rates. Other cable with known water, fuel or other contamination issues or spans with a high failure history are planned for replacement also. Underground structure failures include manhole, pull hole, street vault or ductbank failures (including fiber duct issues). These failures are almost always age related and are repaired or replaced because of loss of use or safety concerns.

Personal Computers

End user devices (laptops and computers) are replaced on a three (3) year cycle, or in alignment with capital budgets. The guideline for computer equipment replacement is to replace with "like for like", unless specific exceptions are requested and approved. Equipment is purchased according to the capital guidelines as defined by Finance. The purpose of the replacement program is to ensure that computing resources meet standards for security, support and business needs.

Fleet

CNP uses consistent vehicle and fleet equipment replacement guidance for budgetary and strategic planning purposes which was developed over the years based on knowledge of utility industry fleet practices and the CNP fleet lifecycle which includes costs from initial acquisition, maintenance and deprecation costs, and salvage costs upon retirement. A matrix, which is attached as COH10-21 Attachment 1, is utilized within Fleet Services to help identify the need for replacement based on the applicable criteria and a goal of maximizing the useful life of fleet assets while providing safe and practical transportation for all aspects of utility operations. A rating system has been established to determine the priority of replacements. There are many factors that determine the actual replacement of a vehicle. While age and mileage are the primary factors, maintenance cost and condition of the asset are considered when they impact the overall performance of the asset. The mileage of the vehicle has a higher weighting than the age of the vehicle and the combined rating of age and mileage is used to determine the priority of replacements.

Annually, Fleet Services evaluates the entire fleet and presents a recommended 5-year capital plan for vehicle and equipment purchases. The plan focuses on a consistent replacement strategy for each class/type of vehicle. The capital fleet plan is assessed in conjunction with the overall business unit capital plan. Economic restrictions may require the business unit to retain vehicles longer than anticipated or high operating cost of existing vehicles may accelerate the replacement of a vehicle. Once approval is received during the annual budgeting process, specific purchases are identified and completed the following year as supported by the plan and utility needs.

Telecommunications

In 2018, Telecommunications started the replacement of the WiMAX radio system used to transport Cell Relay data. This is a result of the WiMAX radio system being obsolete, no longer supported by manufacturer and replacement parts becoming increasingly difficult to find. The WiMAX radio system is being replaced by radios utilizing 700MHz spectrum. This project will continue thru 2021.

Street Lights

The Streetlight Replacement Program will replace high pressure sodium, metal halide and mercury vapor streetlight luminaires with LED streetlight luminaires. This proactive replacement of older streetlights is based on the agreement between CEHE and the City of Houston. Other cities and home associations can elect to participate.

Substation Asset Management Strategy

CEHE uses planned replacements for several types of substation assets including transformers breakers, switches etc. Assets are identified and prioritized for replacement based on risk of failure. Annual capital budget dollars are then allocated for targeted pro-active replacements. Station equipment is prioritized for replacement based on analytics information using factors such as vintage, probability of failure, impact of failure, cost to maintain, design and most importantly condition or health of the asset. Analytics information including diagnostics tests is then used to help determine asset health and make replacement versus repair decisions.

Pro-actively replacing substation equipment before they reach the end of their useful life as determined, or as a result of inspections of substation facilities is an important modernization strategy of the company. However, more equipment of all types installed on CEHE's electric network is identified for replacement that can be replaced in any given year. As such, the strategy at CEHE is to balance resources, outage availability, reliability and system impact to prioritize work that will be accomplished in a given year. Without continued implementation of planned capital replacements, equipment failure rates could rise in response to aging infrastructure, higher load levels and rising fault levels.

Transmission Line Assessment

CEHE's Transmission Line Clearance program annually reviews approximately 20% of the system utilizing Lidar based technology. Lidar aerial surveys are performed, and the data analyzed, to evaluate whether transmission facilities meet the minimum line clearance requirements defined by the National Electric Safety Code (NESC) in affect at the time of the survey. In addition, minimum clearance requirements associated with permits, easement agreements, etc. are also evaluated. When a location has been identified for corrective action, work orders are issued and work is completed to resolve the issue. Depending on the specific circumstance, resolution could include modifications to CEHE transmissions facilities, CEHE distribution facilities or both. These modifications have included the replacement of transmission structures/distribution poles, raising structures, replacement of hardware, relocation of facilities, re-conductoring, etc. In rare circumstances, the undergrounding of facilities would be considered. Also, twenty percent of the transmission system is ground inspected and maintained each year. Any line component that will likely result in an imminent failure is addressed immediately.

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
2019 CEHE RATE CASE
DOCKET 49421-SOAH DOCKET NO. 473-19-3864

PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-24

QUESTION:

In CenterPoint's response to the Staffs first RFI, PUC01-38 Attachment 1, pages 12-15, CenterPoint provides a list of projects and the percentages of cost overruns from the original project cost estimates to the actual project cost. Provide a detailed explanation of, and reasons for, the cost overruns that are greater than 10% of the estimated cost of each of the f ollowing projects. Include and break down the estimated and actual costs into the appropriate FERC accounts:

Project	Cost Overrun
a. W. A. Parrish Sub	10.7%
b. Fort Ben- Rosenberg	40.1 %
c. Flewellen- Rosenberg	49%
d. Ranger Sub	7508%
e. Marine Sub	29%
f. Dow Sub	51%
g. Alexander Island Sub	104%
h. La Marque Sub	92%
i. Sandy Point Sub	89%
j. Jones Creek Sub	29%
k. Springwoods Sub	16%
l. Tanner Sub	16%

ANSWER:

CenterPoint Houston's response to PUC01-38 provided, among other things, the percent difference between the Filed Initial Estimated Project Cost and the Final Actual Project Cost for the listed projects. For some of those projects, the cost decreased between the Filed Initial Estimated Project Cost and the Final Actual Project Cost, and for other projects, the cost increased. In addition, the Filed Initial Estimated Project Costs are developed prior to detailed engineering or construction analysis. CenterPoint Houston's final construction reports compare the final actual cost to the final estimate, rather than the initial estimate. For the projects identified in PUC06-24, CenterPoint Houston provides the following responses regarding the differences between the Filed Initial Estimated Project Cost and the Final Actual Project Cost:

a. **W. A. Parrish Sub - 10.7%:** There were no major scope changes to this project, but a variety of small cost differences to labor and materials resulted in a 10.7% cost difference.

b. **Fort Bend - Rosenberg - 40.1 %:** After the Company initially filed this project, the route was significantly modified due to ROW constraints and negotiations with parties such as the Railroad Museum in Rosenberg. While a small amount of bypass work was in included in the initial estimate, additional bypass work was needed. Crews were mobilized and demobilized more than expected due to the scope changes, resulting in increased labor costs.

c. **Flewellen- Rosenberg - 49%:** This project converted 69kV circuits to 138kV while the substation was also being upgraded. The transmission work needed to be done in parallel with substation work ensure continuity of service. Scheduling parallel work required additional mobilization and demobilization that was not planned for in the initial estimates.

d. **Ranger Sub - 7508%:** The final actual project cost was paid in full by the customer for this project. The company is not seeking recovery of these costs in this case.

e. **Marine Sub - 29%:** The final actual project cost was paid in full by the customer for this project. The company is not seeking recovery of these costs in this case.

f. **Dow Sub - 51%:** The final actual project cost was paid in full by the customer for this project. The company is not seeking recovery of these costs in this case.

g. **Alexander Island Sub - 104%:** Foundations were staked with the wrong line pull orientation which wasn't discovered until after the foundations were built. Foundations were removed and reconstructed. Structures had to be modified and some additional material had to be ordered.

h. **La Marque Sub - 92%:** Tower design and location changed during detailed engineering phase which led to some material errors. One angle structure had to be removed and replaced.

i. **Sandy Point Sub - 89%:** The substation site changed after the initial estimate, requiring more temporary work than expected. Crews were mobilized and demobilized more than expected do the schedule changes, resulting in increased labor costs.

j. **Jones Creek Sub – 29%:** The Jones Creek substation project included in the Company's response to PUC 1-38 covered only the transmission work to connect Jones Creek Substation. No substation construction costs were included. The initial filed estimate for the project was $15,021,000 and the final actual project cost was $13,320,426, representing a -11.3% difference.

k. **Springwoods Sub – 16%:** The Springwoods substation project included in the Company's response to PUC 1-37 covered only the transmission work to connect Springwoods Substation. No substation construction costs were included. The initial filed estimate for the project was $9,547,000 and the final actual project cost was $8,593,292, representing a -10% difference.

l. **Tanner Sub – 16%:** The Tanner substation project included in the Company's response to PUC 1-38 covered only the transmission work to connect Tanner Substation. No substation construction costs were included. The initial filed estimate for the project was $7,417,000 and the final actual project cost was $6,641,378, representing a -10.5% difference.

SPONSOR (PREPARER):
Martin Narendorf (Martin Narendorf)

RESPONSIVE DOCUMENTS:
None

CERTIFICATE OF SERVICE

I hereby certify that on this 17th day of May 2019, a true and correct copy of the foregoing document was served on all parties of record in accordance with 16 Tex. Admin. Code § 22.74.

Martin Brun