Appendix B

Details of the Exposure Calculation Program

Decision Insights, Inc.

The purpose of this appendix is to provide the details of the exposure calculation not covered in the main text. We assume that the reader has some engineering background, as the basic theory cannot be covered here. Referring to the "Specify Line Characteristics" form, Figure 4.8 in Chapter 4 of this report and reproduced below as Figure B.1, this Appendix explains the modeling behind each element shown in that form. In section B.1 the variable loading is covered. In section B.2 the modeling of net currents is described for 4-wire distribution, as well as current unbalance for all circuit types. In section B.3 the addition of background using EMDEX data is further detailed, along with the procedure for using custom sets of EMDEX data. In section B.4 the correlation between circuits either on the same or different structures is covered. In section B.5 custom (user defined) linetypes are covered, as well as some details on the modeling of underground circuits.

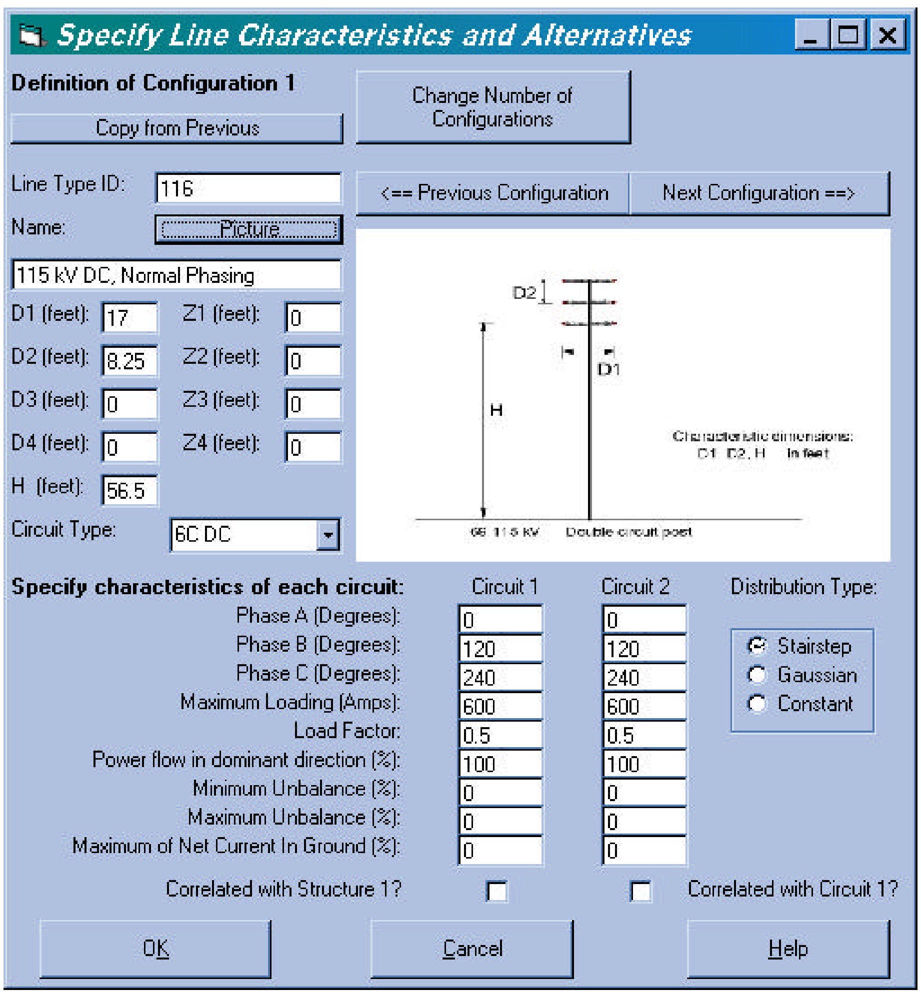


Figure B.1: Form used to specify line characteristics

B.1: Accounting for Variable Circuit Loading

Variable circuit loading was mentioned in the main text, and further details are given here. Initially we used the “Stair Step” approach developed by Bob Olsen (Olsen, 1992). At the request of the SAC we developed a Gaussian distribution approach as well. The user now has the choice between two types of loading distributions and also has the option to consider the loading to be constant.

The Stair Step distribution uses two probability distributions: one to account for daily variations in loading and another to account for annual variations. The daily distribution is assumed to be very simple: approximately constant during three periods of the day. These periods are low-use (middle of the night), medium use (mid-day and later evening), and heavy use (morning and evening). A probability distribution including the three periods is shown in Figure B.2. The figure illustrates why this is called the “Stair-Step” approach. In Figure B.3 an example “maximum daily current” (MDC) distribution is shown, where the probability is assumed to the same for any current in the range of from 500 to 1,000 Amps. The reason this variable is called the “maximum daily current” is that it represents the maximum value of loading for a given day.

There is a fair amount of leeway as to how the two probability distributions can be created, including what percent of the day is high-use, medium-use, and low-use and what the range of values is for the maximum daily current. In order to keep the input form clean and the program automated, the following assumptions are made: (1) the “high-use” daily current factor is 1.0. (2) The magnitudes of the three daily current factors are equally spaced, meaning for example that if the high-use factor is 1.0 and the medium-use is 0.75, then the low-use is 0.5. (3) The daily current factors are equally probable, meaning each of the three periods is about equal in total duration. (4) The ratio of high to low daily current factor is the same as the ratio of maximum to minimum MDC. With the above four assumptions, along with the user-supplied values for the load factor and peak maximum daily current (the rated ampacity), the daily current factors and the range of MDCs are uniquely defined and can be determined.

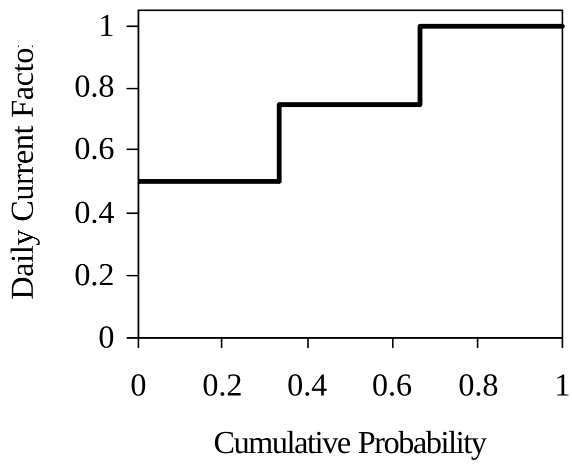


Figure B.2: Example probability distribution of “Daily Current Factors” for the Stair Step approach.

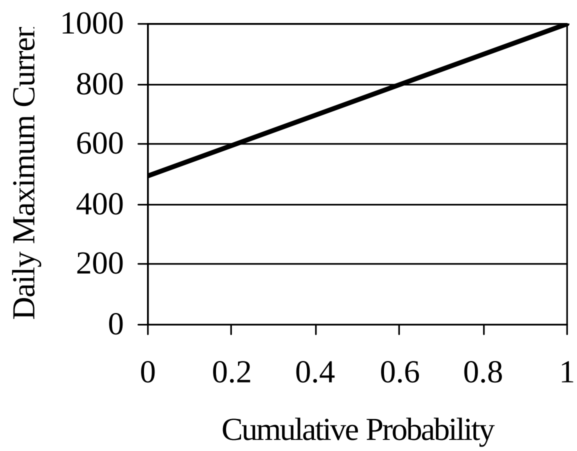


Figure B.3: Example probability distribution showing the range of the “Daily Maximum Current” factor.

Once the two probability distributions are determined, then the current distribution can be calculated using the Monte Carlo. In the case of the first circuit of the structure, the order in which the distribution is sampled is saved in case future circuits are correlated with this one.

The above approach was presented to the SAC in August of 1998, and several SAC members expressed an opinion that a Gaussian distribution might more accurately model the loading variability than the Stair Step approach. In response, we developed a user's option for the user to choose a truncated Gaussian distribution, so that the mean plus or minus two standard deviations of the distribution are included. If the Gaussian is not truncated, currents exceeding the maximum rated ampacity would be allowed. With the user supplied load factor and rated ampacity the mean and the standard deviation are found. The probability distribution is now defined, and the current distribution is determined using the Monte Carlo.

Several current distributions are shown in Figure B.4 – two Gaussian and one Stair Step. The distributions shown in Figures B.2 and B.3 were used to create the "Stair Step LF = 35" distribution shown in Figure B.4. The Stair Step and the lower of the two Gaussians both assume a load factor of 0.35 with a rated ampacity of 1,000 Amps, and are very similar in appearance. In our experience the per-person exposure calculated using these two different probability distributions for the loading does not differ much when the same load factor and rated ampacity are assumed. Finally, if a higher load factor is chosen, then the current distribution becomes narrower: the Gaussian for a load factor of 0.55 is shown in Figure B.4 and is seen to be much narrower than the Gaussian for the 0.35 load factor.

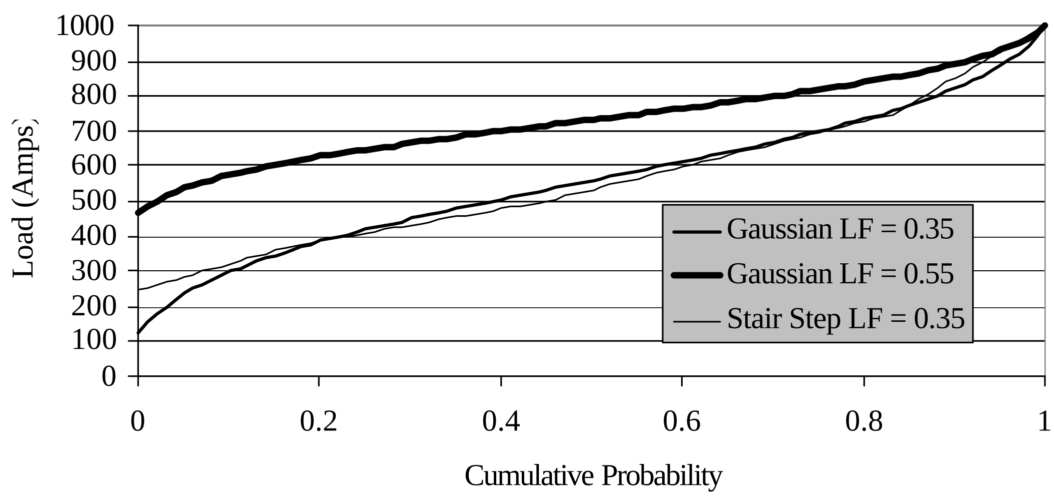


Figure B.4: Cumulative probability distribution of the loading for three cases, assumed Gaussian with load factors of 0.35 and 0.55 and assumed Stair Step with a load factor of 0.35.

B.2: Current Unbalance and Net Current Calculations

In this section we describe how current unbalance is modeled for transmission and distribution circuits and how the return currents are modeled for 4-wire distribution.

Consider the case of a single circuit transmission or distribution line with no neutral. It would appear that the 3 “hot” conductors carry all the current, as there is no obvious alternative current path. Throughout this project, we assumed that there is no unbalance in this type of circuit which results in a return current – a current flowing along other conducting paths. Whether or not there is significant unbalance in transmission circuits and, if so, how much is not fully answered by existing research. Therefore in the exposure program the user is given the option of allowing for unbalance in this type of circuit and may input two parameters: maximum unbalance and minimum unbalance.

Loading at a particular time is determined as follows: first the average loading of the three phases is determined to be, for example, 500 Amps. Then the percent unbalance is chosen from the allowed range using the Monte Carlo simulation, where any unbalance in the allowed range has an equal likelihood of being chosen. If for example the range is from 0% to 5% unbalance, and 2.5% unbalance is chosen, the actual unbalance is 0.025 x 500 = 12.5 Amps. The three currents are then 500, 500+12.5, and 500-12.5 or 500, 512.5, and 487.5 Amps. Which phase is high, medium and low is chosen by the Monte Carlo simulation so that the conductor with the highest loading varies. In order to increase the execution time phase angle was considered to be unaffected by the unbalance.

The second case considered in this section is that of a 4-wire distribution line. In this case the current unbalance can be quite significant, as the transformers are connected phase to ground, and there is no requirement that the current in the three phase conductors be balanced. For example two phases might be carrying 200 Amps and the third 400 Amps. The negative of the vector sum of the 3 phase currents is the return current. Some or all of the return current will return via the fourth wire – the neutral. If all of the return current is in the neutral then there is no “net” current, meaning the vector sum of all the conductors on the distribution pole is zero. In a multi-grounded neutral system, a significant portion of the return current may return by alternate paths, including by the ground or by parallel metallic conductors such as a water main. There may now be a significant “net” current which in turn might result in significantly elevated fields near the pole.

The model employed in the exposure program requires the user to input three variables: minimum unbalance (%), maximum unbalance (%) and maximum of return current in ground (%). Assume for example minimum unbalance is 0%, maximum unbalance is 50%, maximum of return in ground is 20%, and the rated ampacity is 600 Amps. First the average loading of the three phases is determined at a particular time, say 300 Amps. Then, one phase at a time, the loading is determined from the allowed range which here is from 150 Amps (300 Amps – 50%) to 450 Amps (300 Amps + 50%). The loading on the three phases is assumed to be independent. Once the loading of each of the three hots is determined, their vector sum is determined the negative of which is the return current. The percent of the return current returning via the ground is determined by the Monte Carlo simulation. The other part of the return current flows in the neutral conductor.

The reader is cautioned that the unbalance of one 4-wire circuit may be quite different than another. There is a wide range of local circumstances affecting both the unbalance and the percent of return current flowing in the neutral. Are the phases evenly loaded? Is the soil moist and salty or dry? Are there alternate metallic conductors available for the return current such as a metallic water main? The best that the user can do when implementing this model is to make an educated guess based on either local circumstances or perhaps on measured data.

At the verbal and written request of a utility member who participated in one of the SAC meetings the exposure program has been modified so that it can model single-phase primary circuits. The current unbalance is modeled by first assuming that the "return" current is equal to the current on the first phase. Then, unlike the 3-phase case, the % unbalance factor is not used, only the "% returning via ground" factor. So, for phase to neutral, if 250 Amps flows on the phase conductor, and "% returning via ground" is chosen as 10%, then the neutral current is calculated as 250 – (0.1x250) = 225 Amps, 180 degrees out of phase with the phase current. For circuits connected phase to phase, the second conductor is treated the as the neutral conductor above.

B.3: Further Details on How EMDEX is Combined With Source Fields

In this section we provide further details on how the EMDEX data and source fields are combined and cover the procedure for using a user-defined EMDEX dataset to represent background.

Consider the addition of source and EMDEX fields at a particular location, say 50' from the edge of the ROW. Specifically to avoid recalculating the source field each time, it is to be combined with an EMDEX datapoint a 1,000 element field distribution that was previously calculated and stored. Each of the 1,000 field elements contains four values: y-magnitude, y-phase, z-magnitude and z-phase. There are no x-components due to the assumed symmetry in the x-direction for the power lines. The EMDEX data is represented just as a single number: RMS magnitude of the field. The relationship between the EMDEX and source field vector directions is random, and the temporal phases may or may not be correlated.

The first step is to convert the EMDEX datapoint which is the RMS magnitude of a vector into a vector with a time phase. The direction and time phase of this EMDEX vector are assumed random and to be linearly polarized. Three values are determined via a Monte Carlo simulation: two angles which fix the direction of the EMDEX vector and one that represents the time phase. Once the EMDEX vector is determined then it is added component by component with the source element to create the combined vector. At this point the RMS value of the combined vector is calculated, which is then used as input for the effects function calculations.

The wide range of possible background sources makes it important to allow the user freedom as to which EMDEX data to use. We provide two EMDEX datasets for LCC and HCC situations. To describe how the user can include a custom EMDEX dataset we first describe how the standard ones are included.

In the "Choose EMDEX datasets" form, assume the "use low current configuration" is chosen. A file is generated which has the title Emdex_type.txt, which has just one line: Emdex_LCC.txt. For the other available choices the contents of this file would be Emdex_HCC.txt, Emdex_Custom.txt or Emdex_None.txt. When the exposure program is run the Emdex_type.txt file is opened and read, in turn causing Emdex_LCC.txt to be read. The file Emdex_LCC.txt contains the following: on the first line is the number 23, which is the number of EMDEX files, then 23 EMDEX file names are included each on its own line. Note that the following files must be present in the local directory before the exposure program is called: Emdex_type.txt (automatically generated by the VB program), Emdex_LCC.txt, and all 23 EMDEX files. If any of these files are not present the exposure program will crash.

To use a custom set of EMDEX data, the user must include the names of the EMDEX data files to use in the file Emdex_Custom.txt and make sure that each data file is in the correct format. Say that two EMDEX files will be used, HCC99.txt and HCC98.txt. Then the contents of Emdex_Custom.txt is simply:

```
2
HCC99.txt
HCC98.txt
```

where the order of the EMDEX files is not important with respect to the calculation results. The format for the EMDEX data files is straightforward: the number of EMDEX data points is on the first line and the data points follow, each on their own line. If the user has raw EMDEX data to start with it must be converted to mG before storing as the text file to be read by the exposure program.

The last user choice, no background, causes Emdex_None.txt to be stored in the file Emdex_type.txt. Emdex_None.txt refers to Temdex.txt, which in turn contains just 0's – so that a value of zero will be added whenever EMDEX data is required by the exposure program. A user wishing to benchmark the exposure program without background data would use this option.

B.4: Modeling of Circuit Loading Correlation

In this section we discuss the modeling of loading correlation between circuits which could either be on the same or different structures. There are several motivations to do this modeling. When considering the case of a double circuit line – very common in California – the correlation between the loading of the two circuits affects the effectiveness of the "optimum" phase approach, and needs to be taken into account to obtain realistic results. When considering the combined field of different lines on a ROW the correlation between circuits may be important. Finally, the correlation between transmission loading with that of an underbuilt distribution circuit may be important as well.

We discuss first correlation between circuits on the same structure. To model correlation between circuits, we want to know two things: how much of the time does the power flow in the same direction, and is the actual loading correlated? These are both addressed in the model used in the exposure program. One of the user inputs for each circuit in the "Specify Line Characteristics" form is "power flow in dominant direction (%)." What this specifies is the percentage of time the power is assumed to flow in the primary direction – which we will call "positive" power flow. If this number is chosen to be 100%, the power flow is always positive. If the percentage chosen is 66.7% then the power flow is positive 2/3 of the time and negative 1/3 of the time. Thus for a choice of 66.7% about 667 of the 1,000 current elements represent positive power flow and 333 represent negative power flow.

The user also specifies whether a circuit is correlated with the first circuit on the structure. This is done via the checkbox near the lower right hand corner of the "Specify Line Characteristics" form labeled "Correlated with Circuit 1?" If this box is checked off, then when the current distribution for this circuit is created it is precisely correlated with circuit 1. What this means is that the elements of the current distributions are correlated. Assume for example circuit 1 has maximum ampacity of 1,000 amps and circuit 2 has maximum ampacity of 500 amps. Further assuming that both current distributions are created using a Gaussian distribution with a load factor of 0.5, the current on circuit 2 will then be ½ the current on circuit 1 at all times. This type of correlation can make sense in that often the seasonal variations of the loading of two circuits can be very similar, so that the loading might be quite well correlated. Note that if we are going to assume that the loading is correlated, then within this model it makes sense to assume that the power flow of each circuit is in the same direction the same percentage of the time.

We now give some examples of different correlations between circuits to clarify the above discussion. In Figure B.5 the two basic configurations for a double circuit line considered during this project are diagrammed – the ABC-ABC configuration to the left and the ABC-CBA configuration to the right. The ABC-CBA phasing is also used for a split-phase, single circuit configuration as indicated in the figure.

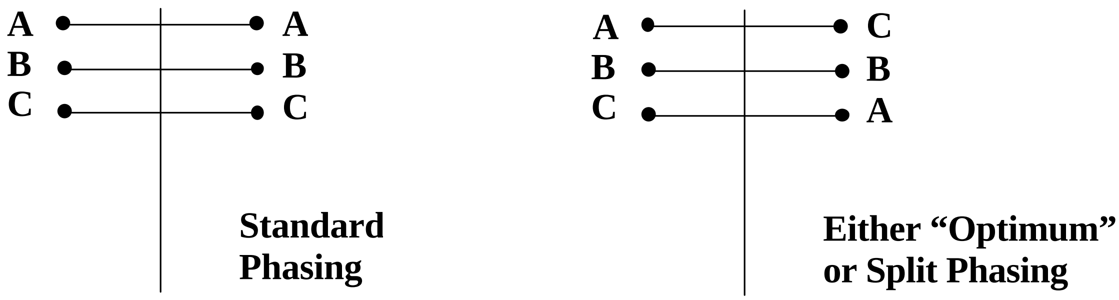


Figure B.5: Diagrams of standard and “optimum” phasing configurations

We have carried out a series of exposure runs using the above configurations. Figure B.6 shows the calculated TWA as a function of distance for the standard and “optimum” phasing configurations. We will keep “optimum” in parentheses as this mitigation strategy does not always optimize exposure reduction, as we will see shortly. The EMDEX file used for this and the subsequent runs is Temdex.txt which has 1,000 0.0’s, so that for the sake of clarity we are modeling the “no background” situation. The assumptions are that the power flow is positive for both circuits at all times and that the loading is not correlated. We see that the “optimum” phase approach gives a good deal of exposure reduction – on the order of a 75% reduction in the TWA.

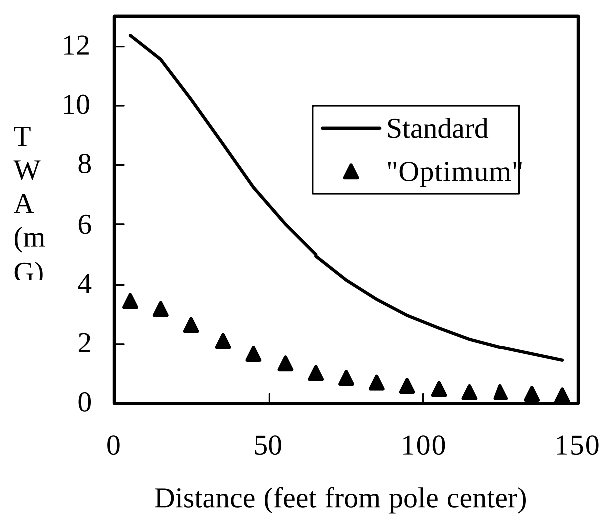


Figure B.6: TWA vs. distance from pole for standard and optimum phasing, assuming power flow direction is the same but that the loading is not correlated.

A second run shows what happens if the power flow is in the opposite direction in the two circuits. The run shown in Figure B.7 is for the case that the first circuit has power flowing only in the positive direction and the second has power flowing only in the negative direction. Again the loading is not considered correlated. Now the roles of the two configurations are reversed: the standard configuration is the low TWA configuration, and the "optimum" configuration has perhaps four times the TWA. In this case adopting a "mitigation" strategy raises the fields significantly.

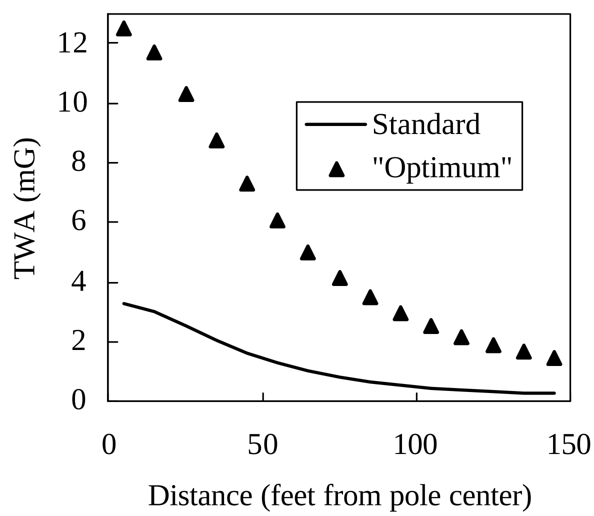


Figure B.7: TWA vs. distance from pole for standard and optimum phasing, assuming power flow is in the opposite direction in the two circuits.

A third run shows the case where the power flow is always positive in circuit 1 and is positive 50% of the time in circuit two. In this case, as can be seen from Figure B.8, nothing is gained from adopting the "optimum" configuration – the fields are the same for both the standard and "optimum" options. Note that the peak TWA of 8.0 mG is about 4.0 mG less than the peak fields for the first two runs: this is because the power is flowing in the same direction ½ the time and opposite ½ the time. Here switching to the "optimum" phasing does not help: ½ the time it mitigates the TWA (when power is flowing in the same direction) and the other ½ of the time it increases the TWA.

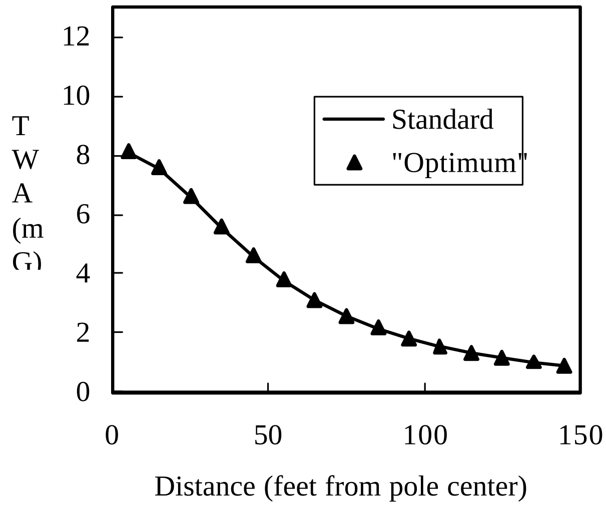


Figure B.8: TWA vs. distance from pole for standard and optimum phasing, assuming power flow direction is not correlated.

The fourth run looks at the case where the two circuits are perfectly correlated. Not only is the power flowing in the same direction at all times, but the loading is correlated. For comparison, the case of a split-phase line is shown where there is only one circuit with double the per-phase loading of each conductor in the double circuit. In Figure B.9 we see the highest fields are for the standard phasing, and these are almost the same as for the standard phasing run in Figure B.6. Switching to an “optimum” configuration results in the most significant TWA reduction seen in this series of runs – perhaps 85%. In fact, the calculated fields are the same as for a split phase design, as can be seen in Figure B.9.

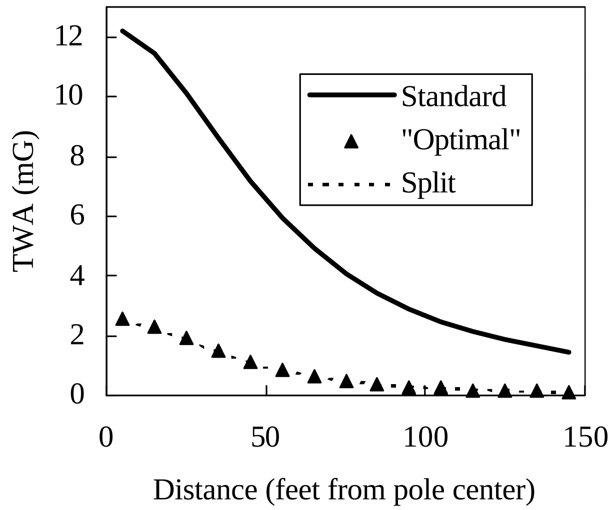


Figure B.9: TWA vs. distance from pole for standard and optimum phasing, assuming power flow is precisely correlated in the two circuits. Split phase results are also shown.

When the “optimum” phase configuration is considered as a mitigation strategy, the effectiveness of this strategy is often assessed overoptimistically by assuming that the two circuits are perfectly correlated. The assumption used when evaluating the “optimum” phase configuration in this project is that the power is flowing in the same direction in both circuits but the loading is not correlated. With these assumptions good TWA reduction is achieved, though not as good as a split phase design. However, if the power flow direction is not correlated between the two circuits then switching the phasing may not buy anything, and as a worse case if the power flow is typically in the opposite direction then switching the phasing actually could give rise to significant field increases. We took our assumptions to be a reasonable intermediate case, which the user may modify.

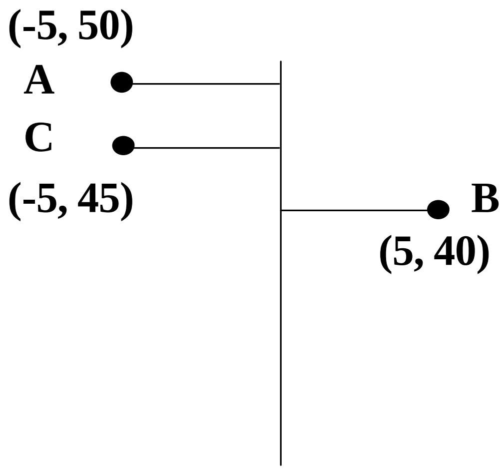
As a final note in this section, the user does have the option of modeling correlation between circuits on different structures. This is done via the checkbox which is labeled “Correlated with Structure 1?” and is located just above the “Cancel” button at the bottom of the “Specify Line Characteristics” form. This box is used for circuit one of the linetype being defined. So for example if structure 1 is a 69kV tri-post, and structure 2 is 12kV distribution underbuild, then if we check the “Correlated with Structure 1?” box when defining structure 2 we are assuming the loading is correlated. This may or may not be reasonable given local considerations.

B.5: User defined linetypes and underground circuit modeling.

In this section we demonstrate the use of the "custom" linetype option and discuss the modeling of distribution underbuild and of underground cables.

A concern expressed by SAC utility members was that some line types in their service areas are not covered by the set of line types developed in the school measurement study. The latest version of the exposure program has the option of including user-defined line types. The exposure program requires the exact position of all conductors in the ROW. For the pre-defined line types conductor locations are calculated automatically based on usually 2-3 geometric factors. When inputting a custom line type, the user proceeds very similarly as for any standard line type, with two differences: 1) the line type ID must be from 700 through 799, and 2) the exact location of each conductor must be input. As an example, consider the single circuit shown in Figure B.10, specifically made non-standard for illustration. To the left is a diagram of the cross-section of the line type, and to the right are the values which would be input in the geometric factors portion of the "Specify Line Characteristics" form for this custom line type.

The user must input the (Y,Z) location of each conductor as follows: the A conductor Y value is D1 and the Z value is Z1. The B conductor Y value is D2 and the Z value is Z2, and similarly for the C conductor. For this line type the D4, Z4 and H values do not matter – though some value must be in those boxes, and 0 is default.



D1 (feet): [-5.0]	Z1 (feet): [50.0]
D2 (feet): [5.0]	Z2 (feet): [40.0]
D3 (feet): [-5.0]	Z3 (feet): [45.0]
D4 (feet): [0]	Z4 (feet): [0]
H (feet): [0]	

Figure B.10: The top part shows the cross section of an illustrative custom line type, including the (Y, Z) pairs. The lower part shows the placement of these values in the custom line type form.

To input a line type of a 4-wire design, the user proceeds as for the 3-wire case, except now the D4 and Z4 values specify the location of the neutral. Also, the user must specify 4-wire as the circuit type. Finally, for the single phase case, D1 and Z1 are for the first "hot" phase, and D2 and Z2 specify the location of either the second "hot" phase or the neutral, depending on the type of distribution system being modeled. Here the circuit type must be specified as "single phase." Beyond the above differences, inputting of line type parameters proceeds exactly the same as it does for the pre-defined line types.

We conclude this section with a discussion of how the various underground configurations are modeled in this project. We have utilized the designs presented in the PG&E Blue Book (PG&E 1994, p. 40) for the solid dielectric triangular configuration, the solid dielectric horizontal configuration, and the pipe type system shown below. The solid dielectric – triangular configuration has an extra duct for redundancy. The value of H, the distance below ground level, is negative and was set at from –3.0' to –5.0' in this project. The pipe-type system has only H and one other geometric factor defining the conductor locations – the conductors are assumed to be equidistant and to form an equilateral triangle. It is worth noting that the fields from a pipe-type system will probably be lower than calculated by the exposure program since currents are induced in the metallic pipe surrounding the conductors that will mitigate the fields. This could be quite a significant effect.

As for any double circuit, the solid dielectric version could be “optimum” phased if the power flow is in the same direction in the two circuits. To model a design with a neutral, one further line type has been created, line type 5. In this type it is assumed that the distribution cables are buried together, as for the pipe type system, and that the neutral is effectively at the center of the three cables. This is an estimate, but we consider it to be a reasonable way to account for the neutral. The user can create a custom line type to model other underground designs.

To choose the underground linetypes, the user specifies:

Solid Dielectric – Triangular Configuration	Line type 1
Solid Dielectric – Horizontal Configuration	Line type 2
Solid Dielectric – Double Circuit	Line type 3
Pipe Type System	Line type 4
Solid Dielectric With Neutral (Distribution)	Line type 5

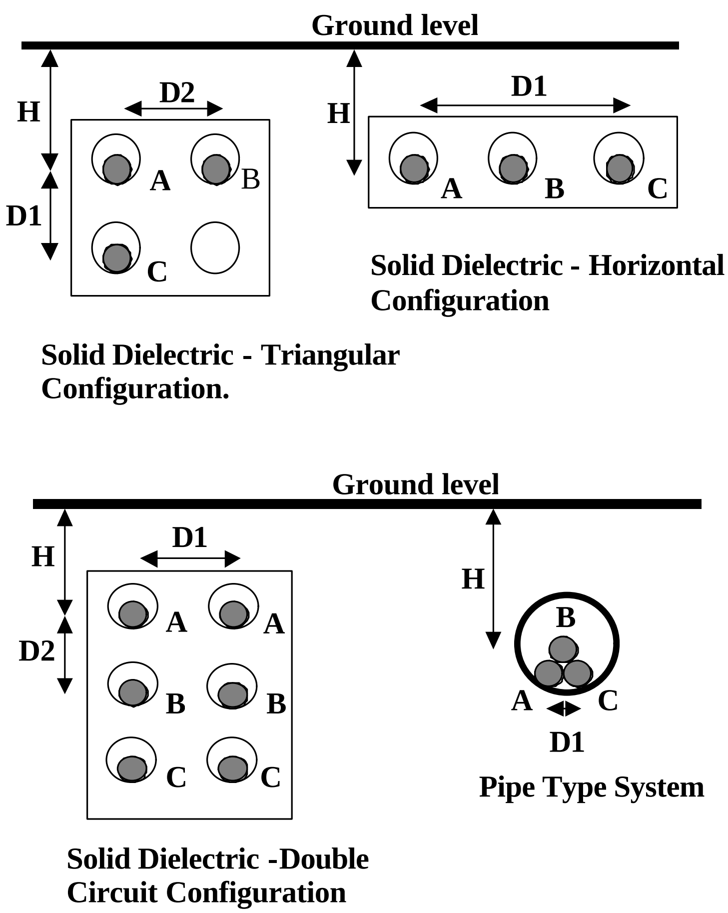


Figure B.11: Four pre-defined underground line types available in the exposure program.