A CONCEPTUAL TRANSMISSION PLAN FOR THE YEAR 2030

FOR THE STATE OF COLORADO

SCENARIO 3

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For the Conceptual Work Group of the
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I. BACKGROUND

The Colorado Coordinated Planning Group (CCPG) created a Conceptual Work Group (CWG) to consider transmission planning issues into the future beyond the 10 year planning horizon required by the Western Electricity Coordinating Council (WECC)/North American Electric Coordination Corporation (NERC) reliability planning criteria. The CWG met for the first time on May 27, 2010. Gerry Stellern, Public Service Company of Colorado transmission planning manager, and Inez G. Dominguez, Colorado Public Utilities Commission staff engineer, volunteered to co-chair the group.

During the course of the first few meetings, the CWG agreed to investigate three scenarios. Scenario 1 would investigate a Colorado transmission plan for a 1000 MW free flowing import/export capability between Colorado, Wyoming, New Mexico, and Utah. Scenario 2 would investigate a solution to a retirement of all the coal fired power plants in the State of Colorado. Scenario 3 would investigate a conceptual transmission plan for a 2030 horizon year with emphasis on solar and wind renewable energy sources.

Inez G. Dominguez volunteered to do Scenario 3. The CCPG accepted the methodology and the conceptual 2030 year conceptual transmission plan for Scenario 3 at its April 27, 2011 meeting. *This report memorializes the methodology and the conceptual transmission plan.*

II. SUMMARY

A. A 2030 year planning horizon

In the mid-1950's, Public Service Company of Colorado (PSCo or Public Service) committed itself to build the 230kV outer belt that starts at the Ft. St. Vrain Switchyard, proceeds in an easterly and westerly direction, interconnects at the Cherokee Switchyard, and continues south to the Daniels Park Substation. Construction of this outer belt started in the early 1960's. In the early 1980's, 230kV lines begin to be built from the outer belt into the inner system's load center. In 2001, the Ft. St. Vrain-Green Valley 230kV transmission line was built. This new 230kV line signaled that the northern portion of the 230kV outer belt was approaching capacity therefore requiring a new line, approximately 40 years later from the initial outer belt 230kV construction. The southern portion of the outer belt still has some room for some transmission lines. A vacant circuit exists on a triple circuit 230kV tower from Waterton Substation to Lookout Substation. Vacant right-of-way (ROW) exists between Daniels Park Substation and Smoky Hill Substation that can accommodate a double circuit 345kV line. It is possible that these potential circuits will be built within the next five years, thus completing the intended use of the outer belt transmission plan. In reality, the planners of the 1950's actually implemented a 50 year plan. With that historical perspective, a future 20+ year transmission plan does not seem unreasonable.

Presently, PSCo has a 10[1] year planning horizon for transmission lines as dictated by the NERC/WECC rules. PSCo takes the 10 year plan approach and incorporates it into its 5-year

[1]The Public Utilities Commission has requested a 10 year plan by February 1, 2012 to be followed by subsequent 10 year plans every even year for Black Hills, Public Service and Tri-State.

capital budget process with a focus on the next three years. On the other hand, the Colorado electric resource planning (ERP) process requires a 20 to 40 year planning horizon with a new ERP process required every 4 years. In reality, there is a timing disconnect between the generation planning process and the transmission planning process. Major new transmission lines take 5-10 years to build and yet they last up to 50 years or longer once they are built. The implication here is that since generation and transmission go hand-in-hand, then the planning of both should have similar planning horizon years. Therefore the transmission planning should also have a 20-40 year planning horizon.

B. A 20 year transmission plan

This report presents an analysis and a process by which future transmission plans can be conceptually developed 20 plus years out into the future for the State of Colorado. Work done by PSCo as required by Colorado Senate Bill 07-100 and information provided by the Colorado Senate Bill 07-091 report were used as a basis for the analysis and preparation of this report. Attached Appendix 1, Tables 1-9, Figures 1 and 2, Map 1, and Drawings 1A-1, 1A-2 and Drawings 1B-1 and 1B-2 reflect a logical progression of the analysis done in coming up with transmission plans for two different generation scenarios – 1) Base case forecast, and 2) a 3% forecast. *The appendix, tables, figures, map, and diagrams are the heart of this report*. Energy resource zones (ERZ's) and the potential generation from renewable energy sources (RES) in each ERZ were used to determine where and how much generation to add in each ERZ.

Table A below is a portion of Table 8. *Table A, in essence, presents in tabular form the results of this study, as it shows the number of transmission lines that would need to be built to accommodate the two (Base Case forecast and 3% forecast) conceptual plans that were developed for the year 2030.*

Transmission planning is traditionally done using maximum peak load conditions, typically occurring in the summer or winter, when generation is at maximum output. Colorado power demand peaks in the hot summer months. Therefore, it makes sense to use the summer peak approach in starting this analysis. In using this approach, and using Table A, we want to examine the transmission lines under the columns heading "Base * Forecast" and compare the columns "Heavy Summer Peak" and "Off-Peak (50% of Peak). In comparing both columns, it can be seen that the off-peak case needs more transmission lines, which implies an additional cost. This need is created by wind generation. We then need to determine early in the planning process whether the additional transmission facilities to accommodate the wind generation should be built or should we only build transmission facilities to handle the heavy summer conditions and deal with the wind generation accordingly to fit into whatever transmission capacity is available. For the purposes of this analysis it was decided to assume the necessary transmission lines would be built to accommodate the wind generation. It should be understood that the transmission lines are necessary to use the total capacity of the generation, to get maximum use of that capital investment. Historically, transmission lines cost less than 10% to build than the cost of generation. It therefore does not make economical sense to skimp on the transmission lines. The desired 2030 transmission system now becomes the greater of the Heavy Summer Peak system or the Off-Peak system. In comparing the columns for the "3% **

Forecast" the results are similar to the Base Forecast – the Off-Peak case requires more transmission lines than the Heavy Summer Peak case.

Year 2030 – Key Transmission Lines	Base * Forecast		3% ** Forecast	
	Heavy Summer Peak	Off-Peak (50% of Peak)	Heavy Summer Peak	Off-Peak (50% of Peak)
1. St. Vrain-Ft. Lupton	2-230kV	2-230kV	2-345kV	2-345kV
2. Pawnee-Missile Site	2-230kV	2-345kV	2-345kV	3-345kV
3. Missile Site-Smoky Hill	2-230kV	2-345kV	2-345kV	3-345kV
4. Missile Site-Daniels Park	1-230kV	1-345kV	1-345kV	1-345kV
5. Missile Site-Big Sandy	2-345kV	3-345kV	3-345kV	4-345kV
6. Big Sandy-Burlington	2-345kV	3-345kV	3-345kv	5-345kV
7. Burlington-Lamar	2-345kV	2-345kV	2-345kV	2-345kV
8. Lamar-Boone-Comanche	1-345kV	3-345kV	2-345kV	4-345kV
9. Lamar-Vilas	1-230kV	2-345kV	1-230kV	2-345kV
10. Vilas-Gladstone	1-230kV	1-230kV	1-230kV	1-230kV
11. Comanche-Midway	1-345kV 2-345kV exist	1-345kV 2-345kV exist	1-345kV 2-345kV exist	2-345kV 2-345kV exist
12. Midway-Daniels Park/Waterton	3-345kV exist	3-345kV exist	1-345kV 3-345kV exist	1-345kV 3-345kV exist
13. San Luis-Poncha	1-230kV 1-230kV exist	1-230kV 1-230kv exist	2-345kV 1-230kV exist	2-345kV 1-230kV exist
14. Poncha-Midway	2-230kV	2-230kV	2-345kV	2-345kV
15. San Luis-Calumet	2-345kV	2-345kV	2-345kV	2-345kV
16. Calumet-Comanche	2-345kV	2-345kV	2-345kV	2-345kV

* From Diagrams 1A-1 and 1A-2
** From Diagrams 1B-1 and 1B-2

Table A

III. CONCLUSIONS - how this long term plan helps the present planning process

A long term transmission plan (20+ years) serves two main purposes. First, it flags potential generation and transmission challenges/problems that may arise in the future, providing sufficient lead times to find the required solutions and a timely framework to implement them. Secondly, it helps to guide the planners in the present to make educated decisions on how to proceed to build the next transmission line. History tells us that the next line when built will last 50 years or longer. So the planner needs to have some confidence based on a long term plan that the transmission line being planned now will still be a useable line at least 25 years after it is built. This conceptual plan can achieve these two purposes if put to practice as discussed below[2].

- As discussed in this report, Diagrams 1A-1, 1A-2 and Diagrams 1B-1, 1B-2 pictorially show the results of this study – generation and associated transmission lines. Since this

[2] **Note:** It is acknowledged that generation built within the load serving network may tend to decrease the need for the transmission lines as outlined in this report. However, internal generation may only postpone the same transmission lines that will eventually be required in the future.

is a long term transmission plan, Table 8 was created to tabulate, from the Diagrams, the generation related transmission lines. Table 8 has a middle column entitled *Projects Under Consideration.* This column shows that from the sixteen identified transmission corridors, only four (10,11, 13, and 14) show "none," that no projects are under consideration for those corridors. Corridors 11, 13, and 14 are needed as a result of the MW demand magnitude of the solar generation modeled at San Luis Substation. Corridor 10 is a place holder for a transmission line needed to Gladstone Substation to eliminate a load shedding remedial action scheme at Gladstone. So from a first inspection, this long term plan is consistent with what is being planned now, adding some credibility to this long term planning concept and associated transmission plan.

- In addition, Table 8 can guide the planner as to which lines to prebuid at 345kV and initially operate at 230kV and how much ROW to buy for the construction of future lines. These can be seen by comparing the Base Forecast lines to the 3% Forecast lines. For example, for the St. Vrain-Ft. Lupton corridor, the Base Forecast shows 2-230kV lines and the 3% Forecast shows 2-345kV lines. This implies that the St. Vrain-Ft. Lupton lines should be built for 345kv and initially operated at 230kV, if necessary. As another example, the Big Sandy-Burlington corridor shows 3-345kV lines in the Base case Forecast and 5-345kV lines in the 3% Forecast. This implies that two double circuit 345kV lines should be built (3 circuits strung) with enough ROW purchased to accommodate a 5^{th} 345kv circuit in the future.

- Although the load serving transmission network was not a part of this study, Table 9 presents a heads-up simple concept as to how many 230kV lines may be needed to serve the future load. This should help the utilities to build 230kV lines even if the need is 115kV initial operation. For PSCo, a comparison of the Base Forecast to the 3% Forecast is a flag that perhaps a planned needed 230kVcircuit should be constructed as a double circuit 230kV line since the 3% forecast requires twice as many 230kV circuits. Table 9 also flags the need to do a long term plan for the load serving transmission network with serious consideration for 230kV lines.

- One of the important flags/findings of this long term study is the great importance of the Comanche-Midway-Daniels Park transmission corridor and the Missile Site-Smoky Hill transmission corridor – see Diagrams 1A-1, 1A-2 and Diagrams 1B-1, 1B-2. These two corridors bring to the outer 230kV belt significant large blocks of power from the generation plants. If a long term plan had existed prior to the 345kV development of these corridors, higher capacity 345kV lines would have been justified than are now being planned and constructed.

- From a renewable energy resource generation perspective, the one third solar generation split and two thirds wind generation split results in wind generation providing 20% of the energy. This 20% wind energy generation results in an 80% of MW nameplate capacity that is 55% of demand load during the off-peak time, chosen as 50% of the heavy summer peak for this study – see Tables 5 and 6. This is definitely a flag to the planners that perhaps there are area control regulation problems during off-peak conditions. This is a flag that a study to address this potential problem is needed. This is also a heads-up to the wind generation folks that this regulation problem is begging for a technical solution that may be found in pumped-hydro generation and/or some energy storage devices such as batteries.

- Historical 2000-2011 peak load demand actual data showed a historical load growth of 2.39%. However, the historical 2000-2007 peak load demand actual data showed a 3.55% average load growth, giving credibility that a 3% forecast used in this study may be a realistic forecast to consider for planning purposes - see Table 1A. Therefore, the information/results provided by the 3% forecast analysis is very useful in providing guidance when considering the 20 year long term planning process.

IV. THE NEXT STEP

The conceptual transmission system, as outlined in Table A above and depicted in attached Diagrams 1A-1, 1A- 2, and Diagrams 1B-1, 1B-2, is a starting point to be followed up with detailed power flow studies simulating the year 2030 system looking at the Base Case forecast load and associated generation. The power flow studies will then be used to verify and fine-tune the conceptual bulk power transmission system. In addition, this 2030 power flow would provide Colorado utilities an opportunity to jointly develop their respective load-serving networks, preferably a 230kV system/network, to feed their respective loads.

V. A DESCRIPTION OF THE APPENDIX, TABLES, FIGURES, MAP, AND DRAWINGS

As mentioned previously, the attached appendix, tables, figures, map, and diagrams are the heart of this report. These are described below.

Appendix 1: This appendix shows the individual demand and energy forecasts of Black Hills Energy (Black Hills), Public Service Company of Colorado, Colorado Springs Utilities, Platte River Power Authority (PRPA), and Tri-State Generation and Transmission Association, Inc. (Tri-State) for the base year 2012 through the future year 2030. These are the base case forecasts of the individual utilities and the composite is referred to as the Base Case forecast.

Table 1: This table shows the 2012-2030 demand forecasts for Black Hills, PSCo, Colo Spgs, PRPA, and T-S. Two forecasts are shown for each utility, the Base forecast and a 3% forecast.

Table 1A: This table shows a tabulation of the actual 2000-2011 historical peak demand load of Black Hills, Public Service, Colorado Springs, Platte River, and Tri-State.

Table 2: This table shows the 2012 and 2030 demand and energy forecast for Black Hills, PSCo, Colo Spgs, PRPA, and T-S. This table calculates a load factor for the 2012 and 2030 Base forecasts which are then used to calculate the energy for the 2012 and 2030 3% forecast.

Table 3: This table calculates the factors to use when allocating the demand portion of the renewable generation and the conventional generation.

Table 4: This table calculates the name plate capacity for wind and solar generation to supply 30% of the energy in 2030 and also calculates the nameplate conventional generation to meet the heavy summer peak.

Table 5: From the Base Case forecast calculations of Table 4, this table allocates per utility the generation capacity for wind and solar generation and the nameplate conventional generation to meet the 2030 heavy summer peak. It also allocates the 80% nameplate capacity of wind generation per utility and the conventional generation capacity available during the off-peak period.

Table 6: From the 3% forecast calculations of Table 4, this table allocates per utility the generation capacity for wind and solar generation and the nameplate conventional generation to meet the 2030 summer peak. It also allocates the 80% nameplate capacity of wind generation per utility and the conventional generation capacity available during the off-peak period.

Table 7: This table allocates per utility the conventional generation capacity at the locations designated by each utility for the Base Case forecast and the 3% forecast.

Table 8: This table tabulates the transmission circuits depicted in Diagrams 1A-1, 1A-2 and Diagrams 1B-1, 1B-2. It also shows a column "Projects Under Construction" that depicts what planned transmission projects may be under consideration by the utilities.

Table 9: This table shows by each individual utility the incremental MW load increase from 2012 to 2030 for the Base Case forecast and the 3% forecast. Based on that MW increase, the table shows the number of new 230kV lines that would be needed to be constructed within their respective load serving networks to serve the load.

Figure 1: For the Base Case forecast, this figure presents in tabular form, on a Colorado map that shows the five energy resource zones, the nameplate generation totals for wind and solar generation and the assumptions used in calculating the nameplate generation for wind and solar**.** The capital letters inside circles identify the substation/plant location for the wind and solar generation.

Figure 2: For the 3% forecast, this figure presents in tabular form, on a Colorado map which shows the five energy resource zones, the nameplate generation totals for wind and solar generation and the assumptions used in calculating the nameplate generation for wind and solar**.** The capital letters inside circles identify the substation/plant location for the wind and solar generation.

Map 1: This map shows the transmission corridors and associated distances in miles used to show where the conceptual transmission lines could be built.

Diagram 1A-1: This diagram shows a conceptual power flow[3] from the generation sites as shown on Figure 1 as the generation is allocated to simulate the 2030 heavy summer peak conditions for the Base Case forecast. The power flow magnitudes are used to determine the voltage level and number of circuits to reliably handle the power they carry between substations and eventually to the Denver-Boulder 230kV outer belt load serving network.

Diagram 1A-2: This diagram shows a conceptual power flow from the generation sites as shown on Figure 1 as the generation is allocated to simulate the 2030 off-peak conditions (50% of heavy summer peak) for the Base Case forecast. The power flow magnitudes are used to determine the voltage level and number of circuits to reliably handle the power they carry between substations and eventually to the Denver-Boulder 230kV outer belt load serving network.

Diagram 1B-1: This diagram shows a conceptual power flow from the generation sites as shown on Figure 2 as the generation is allocated to simulate the 2030 heavy summer peak conditions for the 3% forecast. The power flow magnitudes are used to determine the voltage level and number of circuits to reliable handle the power they carry between substations and eventually to the Denver-Boulder 230kV outer belt load serving network.

Diagram 1B-2: This diagram shows a conceptual power flow from the generation sites as shown on Figure 2 as the generation is allocated to simulate the 2030 off-peak conditions (50% of heavy summer peak) for the 3% forecast. The power flow magnitudes are used to determine the voltage level and number of circuits to reliable handle the power they carry between substations and eventually to the Denver-Boulder 230kV outer belt load serving network.

[3] For Diagrams 1A-1, 1A-2 and Diagrams 1B-1, 1B-2, the power flows were hand drawn by Inez G. Dominguez based on his experience in preparing and looking at actual power flow cases during his career as a transmission system planner.

1. INTRODUCTION – analysis and report

Transmission lines are needed to transfer the power and energy from the power plants or sources to the load serving transmission networks which serve the distribution system where the electric load is located. Serving the electric load is the critical reason generation and its associated transmission lines are needed. Blackouts are an undesirable consequence of not having the necessary generation and transmission to feed the load.

SB 07-100 requires investor owned utilities, namely Public Service Company of Colorado (PSCo or Public Service) and Black Hills Energy (BHE), to identify/create energy resource zones (ERZ) in the state of Colorado that have an effect on their load serving territory and to determine the necessary transmission lines to access these ERZ's to get the power and energy to their load centers. PSCo and BHE have been actively working with interested parties/stakeholders to address potential transmission lines to their identified ERZ's. Per the Senate Bill 07-100 requirements, PSCo and BHE were to submit reports starting in October 31, 2007, and every October 31 of every odd year thereafter, identifying the ERZ's, the transmission plans to access the ERZ's, and the certificates of public convenience and necessity (CPCN) for the transmission lines to be built to the ERZ's.

As the largest electric utility in the state, Public Service has taken the lead in meeting the requirements of Senate Bill 07-100. PSCo has been actively working with interested parties/stakeholders to address potential transmission lines to the ERZ's. In October 31, 2007 PSCo put together a SB 07-100 plan from which a CPCN application for the Pawnee-Smoky Hill 345kV line was submitted to access resources in ERZ-1. PSCo is now working in a set of studies as required by SB 07-100 due October 31, 2011 to come up with its second set of recommended transmission lines and associated CPCN's.

To fulfill SB 07-100 requirements, Public Service with concurrence of the Colorado Coordinated Planning Group (CCPG), created five ERZ for the State of Colorado – ERZ's 1-5. ERZ-1 is in northeastern Colorado; ERZ-2 is in east central Colroado; ERZ-3 is in southeast Colorado; ERZ-4 is in the San Luis Valley; and ERZ-5 is between ERZ-3 and ERZ-4. These ERZ's were consistent with the generation development areas identified in the SB 07-091 report. The SB 07-091 report identifies the potential renewable resource development in terms of GW (billion watts), i.e., ERZ-1 has 25 GW, ERZ-2 28 GW, ERZ-3 37 GW, ERZ-4 20 GW, and ERZ-5 8 GW, for a total of 118 GW. Based on these figures, the generation potential of each ERZ as a percentage of the total is ERZ-1 21%, ERZ-2 24%, ERZ-3 31%, ERZ-4 17%, and ERZ-5 7%.

Recently, the Commission completed hearings on the Colorado electric resource plan (ERP) for Public Service. The emphasis was on renewable resources to meet the resource needs that begin to focus on the ERZ's as the location where the generation could be built. Interestingly, the ERP process with its subsequent generation additions must be coordinated with the SB 07-100 transmission lines planning process. Therefore, a need is created to make the two processes mesh well – generation by default requires transmission lines.

Presently, PSCo fulfills a 10 year planning horizon for transmission lines as dictated by the North American Electric Reliability Corporation (NERC)/Western Electricity Coordinating Council (WECC) rules. In reality, PSCo's operation is governed by a 5-year capital budget process with a focus on the next three years. On the other hand, the ERP requires a 20 to 40 year planning horizon with a new ERP process required every 4 years. There is a timing disconnect between the transmission planning process and the generation planning process.

Major new transmission lines take 5-10 years to be built and yet they last 50 years or longer. The implication here is that since generation and transmission go hand-in-hand, then the planning of both should have similar planning horizon years. Therefore the transmission planning should have a similar 20 to 40 year planning horizon.

The following analysis conceptually looks at transmission planning 20 years into the future, year 2030. The intent of this approach is to provide guidance as to what bulk power transmission system to start to build now that will allow a smooth transition into the future. This approach provides guidance as to how many transmission lines may be needed and what voltage level and conductor size to build the next transmission line from the generation sites to the load centers. This will result in taking the right first step that should help minimize right-of-way issues and expensive upgrades in the future.

Generation planning and the associated transmission lines are needed to feed future load growth. So the basic assumption is that load growth will continue into the future. Therefore company forecasts are the start of generation and transmission planning.

2. ASSUMPTIONS

The following assumptions were used to develop the methodology and the subsequent conceptual transmission plans. These assumptions were recommended and agreed to by members of the Conceptual Work Group (CWG) of CCPG.

a. Demand and energy forecast

Upon agreement by the CWG, BHE, Public Service, Colorado Springs Utilities (CSU), Platte River Power Authority (PRPA), and Tri-State Generation and Transmission Association, Inc. (Tri-State), each provided a "Base Forecast"-see Appendix 1. From these forecasts, a composite demand and energy load forecast was created for the State of Colorado. From the base demand and energy forecast, Inez Dominguez then created a 3% demand and energy forecast- see Tables 1 and 2. Conceptual transmission plans would be developed for the composite Colorado demand and energy load for the Base Case forecast and the 3% Forecast.

A comparison of both forecasts provides useful information. For example, from Table 1, the composite Colorado Base Forecast growth rate is 1.41%. At this 1.41% growth rate, the 2030 demand of 13,139 MW would take an additional 20 years to reach the 2030 demand of 17,479 at 3% growth. In essence, the 3% load growth presents a 40 year plan (year 2050) at a 1.41% load growth.

However, actual historical demand load data tells us that 3% may be a realistic demand load growth. For example, from Table 1A, the actual demand load growth from 2000 to 2007 is 3.55%. In 2007, the state of Colorado demand load peaked at 10,278 MW. In 2009, the demand load bottomed out at 9,466 MW, about an 8% decrease from the 10,278 MW 2007. The 2010 load shows a 5.47% increase from the 2009 load. The 2011 load shows an increase of 4.51% from the 2010 load. Also, note that the 2011 load of 10,434 MW has already exceeded the 10,278 MW of 2007, two years sooner than the 2013 forecasted load at 1.41%. This implies the economy may recover to a higher load growth as has existed in the near past of 2000-2007. This reality says that the 3% load growth forecast results provide useful planning information.

b. Renewables

30% energy generation of the entire Colorado load will be from renewable resources, namely wind generation and solar generation.

1) **Wind generation**

   37% capacity factor (Actual from PSCo data 2010 YTD),
   20% of total on-peak,
   80% of total off-peak,
   Based on cost, will provide 2/3 of renewable energy generation.

2) **Solar Generation**

   Photo voltaic – 25% of total, 30% capacity factor, 65% on on-peak.
   Solar with storage – 75% of total, 50% capacity factor, 95% on on-peak.
   Solar – 0 % off-peak.
   Based on cost, will provide 1/3 of renewable energy generation.

3) **Allocation of renewable generation***

   ERZ1 – 26% of total wind generation.
   ERZ2 – 30% of total wind generation.
   ERZ3 – 39% of total wind generation.
   ERZ4 – 100% of total solar generation.
   ERZ5 – 5% of total wind generation.
   Note:* As per the CWG meeting on January 14, 2011, the group agreed to take half of the Pawnee wind generation and half of the Missile Site generation; add this sum to the Vilas wind generation; take that total and assign one third to the Vilas site, one third to the Lamar site, and one third to the Burlington site. In addition, take the PV total solar generation of the San Luis Valley and add it to the Lamar site, leaving only the solar generation with storage at the San Luis Valley.

c. Transmission Lines

From experience gained in doing transient stability studies, a 1000 MW power plant 200 miles from the load serving network requires three 345kV lines for stability reasons for an N-1 criterion. With three 345kV lines, this assigns 500 MW per circuit after the outage of one circuit. Under this assumption, the transmission plans created in this study and analysis imply that the system is transiently stable. Please note that these lines do not include/have series compensation.

3. 2030 LOAD FORECAST AND ASSOCIATED GENERATION FOR THE STATE OF COLORADO

Attached Table 4 calculates the nameplate capacities for the required wind generation and solar generation to meet 30% of the energy required for the year 2030. It also calculates the demand generation available from wind and solar generation for the heavy summer peak and calculates the nameplate capacity of conventional generation required to meet the 2030 summer peak plus 16% generation reserves. In addition, it also calculates the 80% wind generation capacity available for the off-peak conditions, 50% of the heavy summer peak.

a. Heavy Summer

Traditional transmission planning is done using peak load conditions (typically heavy summer or heavy winter) where the maximum generation on the total system can be expected. These heavy peak periods then define the transmission lines that need to be built to get the power to the load centers. A conceptual plan therefore was created to look at the heavy summer conditions for Colorado since electricity consumption peaks during the summer.

<u>Base Case forecast-summer peak</u>

Using recent Base Case peak demand (MW) and energy load forecasts (see Appendix 1) from BHE, PSCo, CSU, PRPA, and Tri-State, a composite Colorado demand and energy load forecast was created that reflects the majority of the Colorado load. As is the case today, it was assumed that most of the load would continue to develop along the I-25 corridor from Wyoming to New Mexico. The intent of the composite forecast was to use it to plan the required generation and associated transmission system from a one utility concept. The total generation required to serve the Colorado load would then be allocated to the individual utilities to serve their respective loads. The load forecast information from Table 3 shows that the 2012 composite load for these utilities was 10,214 MW for the Base Case forecast. The load increase from 2012 to 2030 is 2925 MW. Assuming a 16% reserve margin, the incremental generation needed to cover this load is 3393 MW. Attached Table 5 allocates from Table 4, on a utility by utility basis, the solar generation, the wind generation, and conventional generation required to meet the Base Case 2030 summer peak.

<u>3% Forecast-summer peak</u>

Using a 3% peak demand (MW) and energy load forecasts (see Table 2) created from the base forecast from BHE, PSCo, CSU, PRPA, and Tri-State, a composite Colorado demand and energy load forecast was created that reflects the majority of the Colorado load. As is the case today, it was assumed that most of the load would continue to develop along the I-25 corridor from Wyoming to New Mexico. The intent of the composite forecast was to use it to plan the required generation and associated transmission system from a one utility concept. The total generation required to serve the Colorado load would then be allocated to the individual utilities to serve their respective loads. The 3% load forecast information from Table 3 shows that the 2012 composite load for these utilities was 13,139 MW. The load increase from 2012 to 2030 is 7108 MW. Assuming a 16% reserve margin, the incremental generation needed to cover this load is 8245 MW. Attached Table 6 allocates from Table 4 on a utility by utility basis the solar, wind, and conventional generation required to meet the 2030 heavy summer peak for the 3% forecast.

b. Off-peak

The off-peak is that time during a 24 hour day when the load demand on the electric system is significantly lower than the daily peak. The off-peak loads are typically the lowest during the night between midnight and 5:00 A.M. The minimum off-peak loads occur at night in the spring and in the fall when the weather is mild. For purposes of this analysis, the off-peak load was assumed as 50% of the summer peak. A 2001 analysis showed PSCo's minimum peak load to be 42% of its maximum summer peak load, so a 50% representation of the summer peaks for the whole state of Colorado appears to be a reasonable representation for off-peak periods.

Base Case-off-peak

The off-peak demand load conditions are expected to occur during the night when wind is assumed at 80% of capacity and solar generation to be at 0% of capacity. The total 80% level of off-peak generation for 2030 is calculated to be 3590 MW. Attached Table 5 allocates, from Table 4 on a utility by utility basis, the wind generation required to meet the 80% level.

An off-peak case was created to present the magnitude of the challenges RES generation presents to the transmission planning picture. The 2030 demand load at 50% of the peak is 6560 MW. This means that wind generation is providing 55% of the demand load with the remaining 45% of the load being supplied by conventional generation. Wind generation providing 55% of the load is a flag that load/generation regulation may be a problem to the balancing authority.

3% Forecast-off-peak

The off-peak demand load conditions are expected to occur during the night where wind is assumed at 80% of capacity and solar generation to be at 0% of capacity. The total 80% level of off-peak generation for 2030 is calculated to be 4778 MW. Attached Table 6 allocates, from Table 4 on a utility by utility basis, the wind generation required to meet the 80% level.

An off-peak case was created to present the magnitude of the challenges RES generation presents to the transmission planning picture. The 2030 demand load at 50% of the peak is 8739 MW. This means that wind generation is providing 55% of the load with the remaining 45% of the load being supplied by conventional generation. Wind generation providing 55% of the load is a flag that load/generation regulation may be a problem to the balancing authority.

4. TRANSMISSION LINES CHARACTERISTICS CONSIDERED/USED IN THE DIFFERENT SCENARIOS OF THIS ANALYSIS

The voltage level of a transmission line (or network) is determined by the distance and the magnitude of power to be transferred from Point A to Point B. The number of lines required depends on the reliability criteria in effect. For this analysis, an N-1 criterion was used, i.e., the loss of the single worst contingency will not result in voltage violations, thermal overloads, remedial action schemes, or stability problems.

The thermal rating of a 3-1272 conductor bundle 500kV line is 3767 MVA; a 2-1272 conductor bundle 345kV line has a rating of 1733 MVA; a 2-1431 conductor bundle 345kV line has a rating of 1852 MVA; a 3-1431 conductor bundle 345kV line has a rating of 2819 MVA; a single 1272 conductor 230kV line has a rating of 578 MVA; a 2-1272 conductor bundle 230kV line has a rating of 1155 MVA. Lines of 50 miles or less in length can be loaded to their thermal rating with minor concerns for voltage regulation and stability problems.

For lines longer than 50 miles, voltage regulation and stability problems begin to show themselves. The power transfer capability of longer lines may be limited by stability considerations, which are typically less than their thermal ratings. A steady state stability limit can be calculated by knowing the receiving end voltage, the sending voltage, the reactance between the receiving and sending voltages, and the electrical angle between them. In this analysis, from experience gained in doing transient stability studies, a 1000 MW power plant 200 miles from the load serving network requires three 345kV lines for stability reasons for an N-1 criterion. With three 345kV lines, this assigns 500 MW per circuit after the outage of one circuit. Under this assumption, the transmission plans created in this study and analysis imply that the system is transiently stable. Please note that these lines do not include/have series compensation.

5. GENERATION LOCATIONS AND SCENARIOS

These load and generation scenarios then present two obvious questions: 1) Where is the new load growth taking place? And, 2) Where should new generation be located in order to feed the new load? For the purpose of this evaluation, it is assumed that load growth is occurring throughout the state of Colorado, but it is also assumed that the load growth is primarily occurring along the I-25 corridor from Wyoming to New Mexico with load growth/expansion of existing cities and towns. Therefore, the generation and associated transmission lines would be built to feed primarily the loads in these cities and town along the I-25 corridor.

It is assumed that the generation to feed the load growth will be built in the identified ERZ's. However, the five identified ERZ's present multiple generation location combinations and it is difficult to determine which is the right combination. But there are several logical location combinations that can be evaluated for transmission planning purposes. The three generation location scenarios that have merit are – 1) a generation balanced approach for heavy summer and off-peak, 2) a heavy north generation schedule approach for heavy summer and off-peak, and 3) a heavy south generation schedule approach for heavy summer and off-peak. These three generation location scenarios proved to be very useful and helpful for studies completed in the early 1980's. The studies provided insight into transmission systems that would be required in the future.

However, for purposes of this study, the ERZ's and their wind generation potential and solar generation potential lent itself to a defendable somewhat balanced approach that was agreed to by the CWG as follows: ERZ1 – 26% of total wind generation; ERZ2 – 30% of total wind generation; ERZ3 – 39% of total wind generation; ERZ4 – 100% of total solar generation; and ERZ5 – 5% of total wind generation (see Figures 1 and 2). **Note:** As per the CWG meeting on January 14, 2011, the group agreed to take half of the Pawnee wind generation and half of the Missile Site generation; add this sum to the Vilas wind generation; take that total and assign one third to the Vilas site, one third to the Lamar site, and one third to the Burlington site. In addition, take the PV total solar generation of the San Luis Valley and add it to the Lamar site, leaving only the solar generation with storage at the San Luis Valley.

Under each ERZ generation scenario, a coordinated transmission network can be developed to bring in the power/energy to the load centers. Transmission networks are presented for the year 2030 for the Base Case forecast and the 3% forecast. For this evaluation, power injection points are identified as follow: ERZ-1 Pawnee; ERZ-2 Missile Site and Burlington; ERZ-3 Lamar and Vilas; ERZ-4 San Luis; and ERZ-5 Calumet. Attached Map 1 presents a conceptual transmission corridor layout from the different ERZ's.

a. Year 2030 Heavy Summer

1) Base Case Forecast (See Diagram 1A-1)

This scenario divides up the 3396 MW of new peak generation (see Table 5 and Table 7) in each ERZ as follows (Gc-conventional generation, Gw-wind generation, Gs-solar generation):

Plant	**Gc**	**Gw**	**Gs**
Rawhide	93	0	0
St. Vrain	181	0	0
Spruce	45	0	0
RMEC	45	0	
Pawnee	181	117	0
Missile Site	0	135	0
Burlington	0	200	0
Lamar	209	201	300
Vilas	0	201	0
Calumet	0	45	0
San Luis	0	0	1315
ERZ 5	56	0	0
Nixon	72	0	0
Total	882	899	1615

2) 3% Forecast (See Diagram 1B-1)

This scenario divides up the 8248 MW of new peak generation (see Table 6 and Table 7) in each ERZ as follows (Gc-conventional generation, Gw-wind generation, Gs-solar generation):

Plant	**Gc**	**Gw**	**Gs**
Rawhide	326	0	0
St. Vrain	1253	0	0
Spruce	313	0	0
RMEC	313	0	
Pawnee	1253	156	0
Missile Site	0	179	0
Burlington	0	267	0
Lamar	836	267	399
Vilas	0	267	0
Calumet	0	60	0
San Luis	0	0	1750
ERZ 5	199	0	0
Nixon	410	0	0
Total	4903	1196	2149

b. Off-peak -50% of Summer Peak

1) Off-peak-Base Case Forecast (See Diagram 1A-2)

This scenario divides up the 3590 MW of new wind generation and the available 882 MW of conventional generation (see Table 5 and Table 7) in each ERZ as follows (Gc-conventional generation, Gw-wind generation, Gs-solar generation):

Plant	**Gc**	**Gw**	**Gs**
Rawhide	93	0	0
St. Vrain	181	0	0
Spruce	45	0	0
RMEC	45	0	
Pawnee	181	467	0
Missile Site	0	539	0
Burlington	0	802	0
Lamar	209	802	0
Vilas	0	802	0
Calumet	0	179	0
San Luis	0	0	0
ERZ 5	56	0	0
Nixon	72	0	0
Total	882	3591	0

2) Off-peak-3% Forecast (See Diagram 1B-2)

This scenario divides up the 4778 MW of new wind generation (see Table 6 and Table 7) and the available 4903 MW of conventional generation in each ERZ as follows (Gc-conventional generation, Gw-wind generation, Gs-solar generation):

Plant	**Gc**	**Gw**	**Gs**
Rawhide	326	0	0
St. Vrain	1253	0	0
Spruce	313	0	0
RMEC	313	0	
Pawnee	1253	621	0
Missile Site	0	717	0
Burlington	0	1067	0
Lamar	836	1067	0
Vilas	0	1067	0
Calumet	0	239	0
San Luis	0	0	0
ERZ 5	199	0	0
Nixon	410	0	0
Total	4903	4778	0

6. WHAT DOES THIS EVALUATION TELL US?

a. Transmission lines planning for the heavy summer peak periods

The traditional heavy summer peak planning and evaluation process tells us conceptually how a back bone bulk power transmission system could be developed for the state of Colorado for the different scenarios as depicted in Diagrams 1A-1 and Diagrams 1B-1and listed in Table 8. For major transmission lines that are being contemplated to be built soon, this conceptual look can help guide the utilities as to how they should build those transmission lines now to fit into an ultimate development of the system that looks 20 years out into the future. This approach would give insight for engineering judgment on how to take the first steps.

RES generation now brings solar generation into the heavy summer peak periods. For purposes of this study, solar generation with thermal storage was all allocated to ERZ-4 in the San Luis Valley area, modeled at San Luis Substation. The solar generation has a significant effect in ERZ-4 and ERZ-5 during the summer peak. For the Base Case forecast, 1315 MW are modeled at San Luis Substation (Diagram 1A-1). For the 3% forecast, 1750 MW are modeled at San Luis Substation (Diagram 1B-1), or 435 MW more than the Base Case forecast. These levels of generation require significant transmission lines from San Luis to the load serving networks north of the San Luis Valley, affecting the transmission lines that terminate at Daniels Park Substation at the southern part of the Denver complex load serving transmission network. In my heavy summer examples, it is assumed that the wind RES generation is at 20% of its nameplate capability and solar at 65% for photovoltaic and 95% for concentrated solar with storage.

b. Transmission lines planning for the off-peak periods

Wind generation presents a totally different challenge to the peak load transmission planning process. For example, wind output changes from about 12.5% of capacity during the summer peak to 100% capacity during the off-peak, an increase of eight times over the summer peak. The problem or challenge requiring a solution is coordinating and dealing with the available conventional generation needed to meet the summer peak with the wind generation during the off-peaks when the wind is at maximum generation output. For the off-peak periods, the wind is assumed at 80% generation and solar is at 0%. The 80% off-peak wind generation has a significant effect on all the ERZ’s except ERZ-4.

c. Comparing heavy summer and off-peak

For the base case forecast 2030 heavy summer peak, from Diagram 1A-1 looking at ERZ-3, a wind rich generation area, Vilas and Lamar are the injection points with 201 MW of generation at Vilas and 710 MW of generation at Lamar for a total of 902 MW. Of these 902 MW, 209 MW would be conventional generation, 402 MW wind generation, and 300 MW of solar generation. The total wind generation capability at Vilas and Lamar is 2010 MW (402 MW *5) of which 80%, or 1608 MW, is shown in the off-peak case (Diagram 1A-2) making the off-peak Vilas plus Lamar total generation capability 1813 MW (1604 + 209). For 2030, the off-peak generation capability at Vilas and Lamar increased by 911 MW (1813-902) over the heavy summer generation, creating the need for additional transmission lines out of the area towards the load centers.

Using the same approach for the 3% forecast, Vilas has 267 MW of generation and Lamar has 1502 MW of generation for a total of 1769 MW for the heavy summer peak (Diagram 1B-1). Of these 1769 MW of generation, 836 MW would be conventional generation, 534 MW wind generation, and 399 solar generation. The total wind generation capability at Vilas and Lamar is 2668 MW of which 80%, or 2134 MW, is shown in the off-peak case (Diagram 1B-2) making the total off-peak Vilas plus Lamar generation 2970 MW (2134+ 836). The available generation at Lamar plus Vilas increases by 1201 MW (2970-1769) for the off-peak case above the heavy summer peak, creating the need for additional transmission lines out of the area towards the load centers - reference Table 8 to see the various transmission lines needed for the different load forecasts and associated generation scenarios.

d. What transmission system should be built?

In this study, for the heavy summer peak scenarios, it is expected that the transmission lines will be built to get the conventional generation plus 20% of the wind generation to the load centers. The solar generation modeled in the San Luis Valley will be on during the peak consistent with the current heavy summer planning practice. Therefore, it is also expected that those transmission lines will be built to get those levels of solar generation from there to the load centers.

For the off-peak conditions, more generation becomes available due to an increase in wind generation, by four times over the summer peak generation for purposes of this study. This increase in generation results in the need for additional transmission lines when compared to the summer peak case. The obvious question then arises, "Should the transmission system be built to accommodate the sum of the total wind generation plus the conventional generation at the injection points? Or, should the conventional generation be reduced at the point of injection so that it matches the injection number of the peak conditions so as to use the summer peak transmission system?" It is recommended to build the transmission system that can accommodate the sum of the total conventional generation plus 80% of the wind generation to meet the load (50% of peak in this analysis) plus reserves. It should be remembered that the transmission system is required to support all the needed wind generation plus the conventional generation. Historically, the cost of transmission is less than 10% of the cost of generation, an obvious bargain.

e. Renewable Energy Sources

The intent of this analysis is to look at the transmission line needs for the future needed generation as identified in the different ERZ's in the different scenarios. However, one of the jobs of a transmission planner is to insure that the transmission system and the generation mesh well together so as to not create instability problems as a result of a disturbance. Another issue that is arising involves the 60 HZ frequency versus load/generation regulation required of the balancing authorities, formerly called area control regulation. Wind generation presents a transmission reliability challenge as well as a balancing authority regulation challenge. The following discussion is presented to raise the issues so that they may be studied and solutions found to the problems before they arise.

Generation of RES is defined in terms of energy (mw-hr) and yet it should be understood that generation has a demand component (MW) to that generation to produce the required energy.

Yet, it is the demand component that creates the problems for wind generation. Each electric system, usually defined as a control area or balancing authority, can handle some maximum amount of generation that it can lose and still meet its area control error. That maximum amount of generation is defined by the control area's ability to ramp up other generation quickly to replace the lost generation. Wind generation has the inherent characteristic that the wind can stop blowing on a moment's notice and therefore the balancing authority needs the ability to replace that lost generation quickly to meet its regulation obligation to the electric system. Let me give you two examples to illustrate this problem. First, in the summer of 2005, Public Service Company of New Mexico (PSNM) had its first commercial wind farm with generation capability of about 200 MW generation. The PSNM control area load was about 2000 MW so the ratio of wind generation to load was about 10%. Shortly after the wind farm started generating, PSNM begin to experience deterioration of its area control regulation during its off-peak conditions when the wind generation was at full capacity and the system load was about 50% of peak or 1000 MW, a generation to load ratio of 20%. In the 2030 off-peak studies presented here, the generation to load ratio is 55%, definitely a flag for an area control regulation study. Secondly, Public Service Company of Colorado in 2004 hired a consultant as part of a study team that looked at various levels of wind generation penetration on its system. The report, finished in 2005, showed that Public Service's system could support 10-15% levels of generation due to the regulation benefits provided by the Cabin Creek Pump-hydro Generation Station. At a 20% level of generation, the model would not solve and the consultant could not tell if that meant there were system technical problems or if it was a program solution problem associated with the computer program. A conclusion of the study was that the regulation capability of Cabin Greek was exceeded at a penetration level greater than 15%.

From the two above examples, the PSNM problem was solved with dynamic generation scheduling of the wind generation to the Arizona control area which had a much larger control area load than PSNM, reducing the generation to load ratio. For the PSCo example above, Cabin Creek provided the needed regulation for the wind generation up to 15% penetration. Additional pumped-hydro generation would have allowed more generation to be added to the PSCo system under study. Obviously, the wind folks definitely need to pay attention to the pumped-hydro complement to wind generation. In addition, there is a power/energy storage device that is waiting to be invented to help the wind generation and fill the gaps when the wind stops blowing.[4]

7. WHAT ABOUT THE LOAD SERVING TRANSMISSION NETWORK?

This analysis did not address the transmission elements required to distribute the power from receiving points on the load serving network to the distribution system. That would require additional analysis to be performed in the near future. But the following are some specific recommendations to keep in mind when developing a load serving transmission network.

[4] Interwest Energy Alliance recommended that this report address 1) faster scheduling, 2) better wind forecasting, 3) access to Energy Imbalance Market, and 3) greater geographic diversity, as tools to assist utilities and balancing authorities to integrate higher amounts of renewables. Although the wind generation allocation in this study incorporates "greater geographic diversity," an extended discussion on the use of these tools is beyond the scope of this analysis.

From an inspection of the "Western Electricity Coordinating Council Map of Principal Transmission Lines," the 500kV lines are depicted as red lines, the 345kV ones as green lines, and the 230kV lines as blue lines. As the transmission lines approach the load centers of the key cities, the load serving transmission lines are blue, or 230kV. The revelation here is that 230kV appears to be the optimal voltage for the load serving transmission system. For Colorado, a 230kV system tracks I-25 from Ft. Collins down to Walsenburg. The 230kV system starts at Ault Substation and continues through the PRPA system down to Fort St. Vrain. From Fort St. Vrain it continues to the south expanding into a 230kV system that loops the Boulder-Denver load area down to Daniels Park Substation. From Daniels Park Substation, it continues through the City of Colorado Springs to Midway Substation and then to the Comanche Generation Station. From Comanche, 230kV lines head to Lamar and Walsenburg. So Colorado already has a significant 230kV load serving network that lends itself for expansion to serve the future load growth. Table 9 presents a conceptual look as to the number of 230kV lines each utility would need to build to serve their individual load.

The above discussion makes a convincing argument that all future new transmission lines that are built to be a part of load serving networks should be built as 230kV lines, even if they are initially energized at a lower voltage. Experience has shown that these 230kV lines can be connected to the various distribution voltages with little difficulty. A typical 230kV circuit with a 1272 kcmil acsr can have a thermal rating of 500-600 MW, depending on the line design, and deliver that amount to the distribution substations. As a rule of thumb, the planner can look at a receiving substation and determine that it needs one 230kV line from there to the load centers for every 500-600 MW of power injection.

Future load serving transmission will have capacity requirements, EMF mitigation needs, and corona noise mitigation needs. To fulfill all these requirements, a utility should consider building its 230kV lines as double circuit lines using a 2-conductor bundle- a 2-1272 bundle operated at 230kV would have a thermal rating of 1000-1200MW. This double circuit construction could then reduce the number of required typical 230kV circuits by one half.

8. CONCLUSIONS - how this long term plan helps the present planning process

A long term transmission plan (20+ years) serves two main purposes. First, it flags potential generation and transmission challenges/problems that may arise in the future, providing sufficient lead times to find the required solutions and a timely framework to implement them. Secondly, it helps to guide the planners in the present to make educated decisions on how to proceed to build the next transmission line. History tells us that the next line when built will last 50 years or longer. So the planner needs to have some confidence based on a long term plan that the transmission line being planned now will still be a useable line at least 25 years after it is built. This conceptual plan can achieve these two purposes if put to practice as discussed below[5].

[5] **Note:** It is acknowledged that generation built within the load serving network may tend to decrease the need for the transmission lines as outlined in this report. However, internal generation may only postpone the same transmission lines that will eventually be required in the future.

- As discussed previously, Diagrams 1A-1, 1A-2 and Diagrams 1B-1, 1B-2 pictorially show the results of this study – generation and associated transmission lines. Since this is a long term transmission plan, Table 8 was created to tabulate, from the Diagrams, the generation related transmission lines. Table 8 has a middle column entitled *Projects Under Consideration.* This column show that from the sixteen identified transmission corridors, only four (10,11, 13, and 14) show "none," that no projects are under consideration for those corridors. Corridors 11, 13, and 14 are needed as a result of the MW demand magnitude of the solar generation modeled at San Luis Substation. Corridor 10 is a place holder for a transmission line needed to Gladstone Substation to eliminate a load shedding remedial action scheme at Gladstone. So from a first inspection, this long term plan is consistent with what is being planned now, adding some credibility to this long term planning concept and associated transmission plan.

- In addition, Table 8 can guide the planner as to which lines to prebuid at 345kV and initially operate at 230kV and how much ROW to buy for the construction of future lines. These can be seen by comparing the Base Forecast lines to the 3% Forecast lines. For example, for the St. Vrain-Ft. Lupton corridor, the Base Forecast shows 2-230kV lines and the 3% Forecast shows 2-345kV lines. This implies that the St. Vrain-Ft. Lupton lines should be built for 345kv and initially operated at 230kV, if necessary. As another example, the Big Sandy-Burlington corridor shows 3-345kv lines in the Base case Forecast and 5-345kV lines in the 3% Forecast. This implies that two double circuit 345kV lines should be built (3 circuits strung) with enough ROW purchased to accommodate a 5^{th} 345kv circuit in the future.

- Although the load serving transmission network was not a part of this study, Table 9 presents a heads-up simple concept as to how many 230kV lines may be needed to serve the future load. This should help the utilities to build 230kV lines even if the need is 115kV initial operation. For PSCo, a comparison of the Base Forecast to the 3% Forecast is a flag that perhaps that a planned needed 230kVcircuit should be constructed as a double circuit 230kV line since the 3% forecast requires twice as many 230kV circuits. Table 9 also flags the need to do a long term plan for the load serving transmission network with serious consideration for 230kV lines.

- One of the important flags/findings of this long term study is the great importance of the Comanche-Midway-Daniels Park transmission corridor and the Missile Site-Smoky Hill transmission corridor – see Diagrams 1A-1, 1A-2 and Diagrams 1B-1, 1B-2. These two corridors bring to the outer 230kV belt significant large blocks of power from the generation plants. If a long term plan had existed prior to the 345kV development of these corridors, higher capacity 345kV lines would have been justified than are now being planned and constructed.

- From an renewable energy resource generation perspective, the one third solar generation split and two thirds wind generation split results in wind generation providing 20% of the energy. This 20% wind energy generation results in an 80% of MW nameplate capacity that is 55% of demand load during the off-peak time, chosen as 50% of the heavy summer peak for this study – see Tables 5 and 6. This is definitely a flag to the planners that perhaps there are area control regulation problems during off-peak conditions. This is a flag that a study to address this potential problem is needed. This is also a heads-up to the wind generation folks that this regulation problem is begging for a technical solution that may be found in pumped-hydro generation and/or some energy storage devices such as batteries.

- Historical 2000-2011 peak load demand actual data showed a historical load growth of 2.39%. However, the historical 2000-2007 peak load demand actual data showed a 3.55% average load growth, giving credibility that a 3% forecast used in this study may be a realistic forecast to consider for planning purposes - see Table 1A. Therefore, the information/results provided by the 3% forecast analysis is very useful in providing guidance when considering the 20 year long term planning process.

The following **ATTACHMENTS f**ollow this page

Appendix 1

Table 1

Table 1A

Table 2

Table 3

Table 4

Table 5

Table 6

Table 7

Table 8

Table 9

Figure 1

Figure 2

Map 1

Diagram1A-1

Diagram1A-2

Diagram1B-1

Diagram1B-2

Black Hills

Appendix A – Load Forecast Information and Class Load Profiles

Table A-1
Peak Demand and Annual Energy Forecast – Base Case

Year	RES (GWh)	COM (GWh)	IND (GWh)	WHO (GWh)	OTH (GWh)	Total Sales (GWh)	Sales Growth (GWh)	T&D Losses (GWh)	Total Energy (GWh)	T&D Losses	Summer Peak (MW)	Winter Peak (MW)	Annual Load Factor
1996	466.7	487.7	330.4	2.7	64.9	1352.4		100.5	1452.9	6.9%	247.0	242.0	67.0%
1997	468.6	520.6	355.1	0.4	77.6	1422.3	69.9	117.1	1539.4	7.6%	263.0	236.0	66.8%
1998	481.0	552.7	383.9	0.5	63.8	1481.8	59.5	112.8	1594.6	7.1%	272.0	260.0	66.9%
1999	484.1	561.7	406.4	0.6	65.6	1518.4	36.6	109.9	1628.3	6.7%	280.0	257.0	66.4%
2000	507.4	587.4	417.2	0.5	71.9	1584.3	65.9	130.6	1714.9	7.6%	292.0	268.0	66.9%
2001	517.0	587.2	372.3	0.5	80.9	1557.8	-26.5	105.0	1662.8	6.3%	297.0	258.0	63.9%
2002	542.9	604.3	410.1	0.1	85.8	1643.1	85.4	113.7	1756.9	6.5%	319.0	278.0	62.9%
2003	545.9	610.8	505.5	0.2	66.7	1729.1	85.9	100.6	1829.7	5.5%	345.0	274.0	60.5%
2004	535.2	623.6	512.1	0.1	63.8	1734.9	5.8	152.3	1887.1	8.1%	347.0	289.0	61.9%
2005	569.4	636.3	539.2	0.1	46.7	1791.6	56.8	122.9	1914.6	6.4%	366.0	297.0	59.7%
2006	572.0	665.9	544.4	0.6	41.8	1824.8	33.1	114.1	1938.9	5.9%	357.0	297.0	62.0%
2007	593.7	686.4	532.5	0.4	40.0	1853.1	28.3	106.6	1959.6	5.4%	372.0	316.0	60.1%
2008	598.9	701.4	541.0	0.4	39.9	1881.7	28.6	122.7	2004.3	6.1%	369.0	325.0	61.8%
2009	612.2	722.6	565.6	0.4	40.1	1940.9	59.2	126.5	2067.4	6.1%	378.0	334.0	62.4%
2010	625.7	744.5	583.3	0.4	40.3	1994.2	53.4	130.0	2124.2	6.1%	388.0	341.0	62.5%
2011	656.9	758.0	608.2	0.4	41.8	2065.2	71.0	134.6	2199.9	6.1%	397.0	350.0	63.3%
2012	672.5	780.4	622.0	0.4	41.6	2117.0	51.8	138.0	2255.0	6.1%	406.0	359.0	63.2%
2013	687.0	798.8	638.0	0.4	41.6	2165.8	48.8	141.2	2307.0	6.1%	415.0	368.0	63.5%
2014	702.5	819.8	652.8	0.4	41.6	2217.1	51.3	144.5	2361.7	6.1%	424.0	376.0	63.6%
2015	718.6	839.9	667.4	0.4	41.6	2267.9	50.8	147.8	2415.8	6.1%	433.0	385.0	63.7%
2016	736.1	862.8	681.8	0.4	41.6	2322.7	54.8	151.4	2474.1	6.1%	442.0	394.0	63.7%
2017	752.4	881.9	697.6	0.4	41.6	2374.0	51.3	154.8	2528.8	6.1%	452.0	403.0	63.9%
2018	770.0	904.1	712.3	0.4	41.6	2428.5	54.4	158.3	2586.8	6.1%	461.0	412.0	64.1%
2019	788.1	926.8	726.3	0.4	41.6	2483.2	54.8	161.9	2645.1	6.1%	471.0	421.0	64.1%
2020	807.7	952.2	740.3	0.4	41.6	2542.3	59.0	165.7	2708.0	6.1%	481.0	430.0	64.1%
2021	827.1	974.2	754.9	0.4	41.6	2598.2	55.9	169.4	2767.6	6.1%	491.0	440.0	64.3%
2022	846.8	997.2	772.0	0.4	41.6	2658.1	59.9	173.3	2831.4	6.1%	501.0	450.0	64.5%
2023	867.4	1021.0	789.4	0.4	41.6	2719.8	61.7	177.3	2897.1	6.1%	512.0	460.0	64.6%
2024	888.6	1044.9	804.9	0.4	41.6	2780.5	60.6	181.3	2961.7	6.1%	522.0	470.0	64.8%
2025	910.5	1069.5	821.3	0.4	41.6	2843.3	62.8	185.3	3028.7	6.1%	533.0	480.0	64.9%
2026	932.9	1094.6	837.2	0.4	41.6	2906.8	63.4	189.5	3096.2	6.1%	544.0	491.0	65.0%
2027	955.8	1120.2	853.1	0.4	41.6	2971.2	64.4	193.7	3164.9	6.1%	556.0	502.0	65.0%
2028	979.4	1146.3	869.2	0.4	41.6	3036.9	65.7	198.0	3234.9	6.1%	567.0	513.0	65.0%
2029	1003.6	1173.2	885.5	0.4	41.6	3104.3	67.4	202.4	3306.7	6.1%	579.0	524.0	65.2%
2030	1028.4	1200.8	902.9	0.4	41.6	3174.2	69.8	206.9	3381.1	6.1%	591.0	535.0	65.3%
Growth:													
1996-2006	2.1%	3.2%	5.1%	-13.9%	4.3%	3.0%		6.8%	2.9%	6.8%	3.8%	2.1%	-0.8%
2007-2010	1.8%	2.7%	3.1%	0.0%	0.3%	2.5%		5.9%	2.7%	5.9%	1.4%	2.6%	1.3%
2008-2030	2.5%	2.5%	2.4%	0.0%	0.2%	2.4%		2.4%	2.4%	0.0%	2.2%	2.3%	0.2%

** Actual 1996-2007, Forecast 2008-2030*

Public Service Company

Inez,

See Below

Subject: PSCO peak demand and annual energy 2010-2030

Peak load demand for PSCo retail and wholesale customers in MW. Does not include Black Hills after 2011.

		Energy GWH
2010	6490	32328
2011	6542	35319
2012	6350	33984
2013	6495	34529
2014	6628	34972
2015	6742	35750
2016	6861	36250
2017	6949	36839
2018	7035	37650
2019	7126	38037
2020	7225	38761
2021	7321	39604
2022	7292	39385
2023	7375	39369
2024	7455	40417
2025	7530	40680
2026	7606	41236
2027	7680	41987
2028	7710	42353
2029	7779	42771
2030	7850	43483

250 MW was removed from the peak forecast when IREA and Holy Cross purchase their 250 MW from the Comanche power plant. You will have to add that 250 MW back in to get the total load forecast. The energy associated with the 250 MW is also not included in the energy.

Colorado Springs Utilities

Electric Energy and Peak Demand Long Term
2010 Forecast

	Energy Including Losses GWH	Peak Demand - MW
2010	4,608	824
2011	4,623	830
2012	4,635	834
2013	4,638	834
2014	4,663	837
2015	4,686	839
2016	4,761	847
2017	4,811	856
2018	4,882	872
2019	4,970	889
2020	5,036	901
2021	5,099	913
2022	5,132	923
2023	5,196	937
2024	5,274	952
2025	5,355	969
2026	5,441	986
2027	5,529	1,004
2028	5,619	1,034
2029	5,708	1,053
2030	5,803	1,072

PRPA 2010-2030 Conceptual L&R

June 15, 2010

LOAD Forecast

	[illegible]		Annual Energy (GWh)	Annual Growth
2010	637		3,157	
2011	652	2.4%	3,218	1.9%
2012	668	2.4%	3,279	1.9%
2013	683	2.3%	3,341	1.9%
2014	699	2.3%	3,402	1.8%
2015	714	2.2%	3,463	1.8%
2016	729	2.1%	3,523	1.8%
2017	744	2.1%	3,584	1.7%
2018	759	2.0%	3,644	1.7%
2019	774	2.0%	3,704	1.6%
2020	792	2.3%	3,780	2.0%
2021	811	2.3%	3,855	2.0%
2022	829	2.3%	3,931	2.0%
2023	847	2.2%	4,008	1.9%
2024	866	2.2%	4,085	1.9%
2025	884	2.1%	4,162	1.9%
2026	902	2.1%	4,239	1.9%
2027	921	2.0%	4,317	1.8%
2028	939	2.0%	4,395	1.8%
2029	957	2.0%	4,473	1.8%
2030	976	1.9%	4,551	1.7%
	Growth 2010-2030	2.2%		1.8%

Note: The data contained to the left is adjusted for estimated DSM savings.

CONCEPTUAL RESOURCE Forecast

	MW	Year	Location
Wind	20	2015	SW WY or NE CO
	7	2017	SW WY or NE CO
	32	2020	SW WY or NE CO
	12	2021	SW WY or NE CO
	10	2023	SW WY or NE CO
	22	2026	SW WY or NE CO
	13	2027	SW WY or NE CO
	10	2030	SW WY or NE CO
Wind Total	126		
Natural Gas, Type FA	128	2018	Rawhide
	128	2024	Rawhide
NG Total	256		

Tri-State

Section 3606 (a) (i): Base Case Load Forecast

	TOTAL 44 MEMBERS			COLORADO JURISDICTION			OTHER STATE JURISDICTIONS		
Year	Annual Energy (GWh)	Summer Peak (MW)	Winter Peak (MW)	Annual Energy (GWh)	Summer Peak (MW)	Winter Peak (MW)	Annual Energy (GWh)	Summer Peak (MW)	Winter Peak (MW)
2011	15,489	2,668	2,243	9,718	1,670	1,467	5,770	997	776
2012	15,734	2,705	2,281	9,928	1,706	1,500	5,807	999	782
2013	15,937	2,736	2,319	10,102	1,733	1,532	5,835	1,002	787
2014	16,201	2,778	2,370	10,319	1,769	1,572	5,882	1,009	797
2015	16,535	2,835	2,425	10,571	1,810	1,615	5,964	1,025	810
2016	16,846	2,882	2,475	10,810	1,848	1,654	6,036	1,034	821
2017	17,143	2,930	2,524	11,037	1,884	1,692	6,106	1,046	832
2018	17,453	2,978	2,578	11,273	1,922	1,734	6,180	1,056	844
2019	17,792	3,032	2,636	11,520	1,962	1,778	6,272	1,070	859
2020	18,144	3,087	2,691	11,777	2,004	1,819	6,367	1,083	872
2021	18,444	3,132	2,740	11,995	2,037	1,856	6,449	1,095	884
2022	18,775	3,185	2,795	12,239	2,077	1,898	6,536	1,108	897
2023	19,117	3,238	2,853	12,493	2,117	1,942	6,624	1,121	911
2024	19,480	3,295	2,910	12,762	2,161	1,985	6,718	1,134	924
2025	19,810	3,345	2,963	13,004	2,198	2,026	6,805	1,147	937
2026	20,153	3,399	3,018	13,259	2,240	2,068	6,894	1,160	950
2027	20,490	3,450	3,076	13,510	2,279	2,112	6,980	1,171	964
2028	20,859	3,510	3,131	13,783	2,325	2,154	7,076	1,185	977
2029	21,165	3,554	3,181	14,011	2,359	2,193	7,154	1,195	988
2030	21,503	3,608	3,236	14,263	2,400	2,234	7,240	1,208	1,001

State of Colorado
2012-2030 Demand Forecast

	Black Hills			**PSCo**			**Colo Spgs**			**PRPA**			**T-S**			IREA			
Year	MW	Growth Base %	Demand @ 3% MW	MW	Growth Base %	Demand @ 3% MW	MW	Growth Base %	Demand @ 3% MW	MW	Growth Base %	Demand @ 3% MW	MW	Growth Base %	Demand @ 3% MW	Demand MW	Total Base MW	Base Growth %	Total 3% MW
2012	406		410	6350		6464	834		847	668		674	1,706		1725	250	10,213		10,370
2013	415	2.2%	422	6495	2.3%	6658	834	0.0%	872	683	2.3%	694	1,733	1.6%	1777	250	10,410	1.92%	10,674
2014	424	2.2%	435	6628	2.0%	6858	837	0.4%	899	699	2.3%	715	1,769	2.0%	1830	250	10,606	1.88%	10,986
2015	433	2.1%	448	6742	1.7%	7064	839	0.3%	926	714	2.2%	736	1,810	2.3%	1885	250	10,788	1.72%	11,308
2016	442	2.1%	461	6861	1.8%	7276	847	1.0%	953	729	2.1%	759	1,848	2.1%	1942	250	10,977	1.75%	11,640
2017	452	2.3%	475	6949	1.3%	7494	856	1.0%	982	744	2.1%	781	1,884	2.0%	2000	250	11,135	1.44%	11,982
2018	461	2.0%	489	7035	1.2%	7719	872	2.0%	1,011	759	2.0%	805	1,922	2.0%	2060	250	11,300	1.48%	12,334
2019	471	2.2%	504	7126	1.3%	7950	889	1.9%	1,042	774	2.0%	829	1,962	2.1%	2122	250	11,472	1.52%	12,696
2020	481	2.1%	519	7225	1.4%	8189	901	1.4%	1,073	792	2.3%	854	2,004	2.2%	2185	250	11,654	1.59%	13,070
2021	491	2.1%	535	7321	1.3%	8434	913	1.3%	1,105	811	2.3%	879	2,037	1.7%	2251	250	11,823	1.45%	13,454
2022	501	2.0%	551	7292	0.0%	8687	923	1.1%	1,138	829	2.3%	906	2,077	2.0%	2318	250	11,872	0.42%	13,850
2023	512	2.2%	567	7375	1.1%	8948	937	1.4%	1,172	847	2.2%	933	2,117	1.9%	2388	250	12,038	1.39%	14,258
2024	522	2.0%	584	7455	1.1%	9217	952	1.7%	1,208	866	2.2%	961	2,161	2.1%	2459	250	12,206	1.40%	14,679
2025	533	2.1%	602	7530	1.0%	9493	969	1.7%	1,244	884	2.1%	990	2,198	1.7%	2533	250	12,364	1.29%	15,111
2026	544	2.1%	620	7606	1.0%	9778	986	1.8%	1,281	902	2.1%	1019	2,240	1.9%	2609	250	12,528	1.33%	15,557
2027	556	2.2%	638	7680	1.0%	10071	1,004	1.8%	1,320	921	2.0%	1050	2,279	1.7%	2687	250	12,689	1.29%	16,017
2028	567	2.0%	657	7710	0.4%	10373	1,034	3.0%	1,359	939	2.0%	1082	2,325	2.0%	2768	250	12,825	1.07%	16,490
2029	579	2.1%	677	7779	0.9%	10685	1,053	1.8%	1,400	957	2.0%	1114	2,359	1.5%	2851	250	12,977	1.19%	16,977
2030	591	2.1%	697	7850	0.9%	11005	1,072	1.9%	1,442	976	1.9%	1147	2,400	1.8%	2937	250	13,139	1.25%	17,479
Ave		0.379 2.11%	0.030		0.218 1.21%			0.254 1.41%			0.383 2.13%			0.345 1.92%				0.253763 1.41%	

IGD 03/21/2011

Table 1

Colorado Utilities
Actual Historical Demand
2000-2010 - MW

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Black Hills	292	297	319	345	347	366	357	372	369	378	388	392
Public Service	5502	5619	6034	6419	6421	6785	6629	6911	6701	6170	6510	6862
Colo Springs	739	740	779	820	817	863	862	907	898	820	867	921
Platte River	466	497	533	560	576	618	603	635	634	576	615	639
Tri-State	1052	1083	1208	1258	1273	1359	1373	1453	1544	1522	1604	1620
Total - MW	8051	8236	8873	9402	9434	9991	9824	10278	10146	9466	9984	10434
% growth per year		2.30	7.73	5.96	0.34	5.90	-1.67	4.62	-1.28	-6.70	5.47	4.51
% Average growth 2000-2011	2.39											
% Average growth 2000-2007	3.55											

IGD - 10/21/2011

Table 1A

Forecast by Utility
Demand and Energy
2012 and 2030 Base and 3%

Black Hills

Year	Base MW	Base Energy Gwh	LF	Growth 3% MW	Energy 3% GWh
2012	406	2255	0.634	410	2277
2030	591	3381	0.653	697	3987

PSCo

Year	Base MW	Base Energy Gwh	LF	Growth 3% MW	Energy 3% GWh
2012	6350	33984	0.611	6464	34594
2030	7850	43483	0.632	11005	60959

CSU

Year	Base MW	Base Energy Gwh	LF	Growth 3% MW	Energy 3% GWh
2012	834	4635	0.634	847	4707
2030	1072	5803	0.618	1442	7806

PRPA

Year	Base MW	Base Energy Gwh	LF	Growth 3% MW	Energy 3% GWh
2012	668	3279	0.560	674	3308
2030	976	4551	0.532	1147	5348

T-S

Year	Base MW	Base Energy Gwh	LF	Growth 3% MW	Energy 3% GWh
2012	1706	9928	0.664	1725	10039
2030	2400	14263	0.678	2937	17454

IREA

Year	Base MW	Base Energy Gwh	LF	Growth 3% MW	Energy 3% GWh
2012	250	1245	0.568	250	1245
2030	250	1245	0.568	250	1245

IGD 03/21/2011

Table 2

Colorado Demand and Energy Forecast - Long Term Planning
2012-2030 Change

Base Case

Year	2012			2030				Change 2012-2030		
Utility	Base MW	Energy GWh	30% Energy GWh	Base MW	Energy GWh	30% Energy GWh	Energy Part of Total Decimal	Base MW	Part of MW Decimal	Energy GWh
Black Hills	406	2255	677	591	3381	1014	0.046	185	0.063	1126
PSCo	6350	33984	10195	7850	43483	13045	0.598	1500	0.513	9499
IREA	250	1245	374	250	1245	374	0.017	0	0.000	0
CSU	834	4635	1391	1072	5803	1741	0.080	238	0.081	1168
PRPA	668	3279	984	976	4551	1365	0.063	308	0.105	1272
T-S	1706	9928	2978	2400	14263	4279	0.196	694	0.237	4335
Total	10214	55326	16598	13139	72726	21818		2925		17400

3% Forecast

Year	2012			2030				Change 2012-2030		
Utility	3% MW	Energy GWh	30% Energy GWh	3% MW	Energy GWh	30% Energy GWh	Energy Part of Total Decimal	3% MW	Part of MW Decimal	Energy GWh
Black Hills	410	2275	683	697	3990	1197	0.041	287	0.040	1715
PSCo	6464	34596	10379	11005	60959	18288	0.630	4541	0.639	26363
IREA	250	1245	374	250	1245	374	0.013	0	0.000	0
CSU	847	4709	1413	1442	7805	2342	0.081	595	0.084	3096
PRPA	674	3310	993	1147	5351	1605	0.055	473	0.067	2041
T-S	1725	10038	3011	2937	17450	5235	0.180	1212	0.171	7412
Total	10370	56173	16852	17478	96800	29040		7108		40627

Incremental Generation Needed With 16% Reserves

Reserves	MW
Base Forecast	3393
3% Forecast	8245

IGD 03/21/2011

Table 3

Year 2030
State of Colorado

	Base				3%			
Demand and Energy Forecast	**MW**	**Energy MWh**	**30% Energy MWh**	**Change From 2012 MW**	**MW**	**Energy MWh**	**30% Energy MWh**	**Change From 2012 MW**
	13139	72726000	21818000	2926	17478	96799000	29040000	7108
Name Plate Calculations for Wind Gen and Solar Gen								
Wind Gen = 2/3 *30% of Energy			14545333				19360000	
Solar Gen = 1/3 *30% of Energy			7272667				9680000	
Wind Gen Demand at 37% load factor	4488				5973			
Solar Gen Demand	1845				2456			
Photo voltaic is 25% of total, 30% load factor	461				614			
With Storage is 75% of total, 50% load factor	1384				1842			
On- peak and off-Peak Calculations for Wind Gen and Solar Gen								
Wind generation 20% on-peak	898				1195			
Wind generation 80% off-peak	3590				4778			
Solar generation								
Photovoltaic 65% on-peak	300				399			
With storage 95% on-peak	1315				1750			
Photovoltaic 0% off-peak	0				0			
With storage 0% off-peak	0				0			
Conventional Gen Required including 16% reserves	882				4902			

IGD 03/21/2011

Table 4

Base Case Forecast

Heavy Summer
Inc. Generation for 2030

Utility		Energy Fraction of need	Gs(PV) 300	Gs(CS) 1315	Gw 898	Demand Fraction of Need	Gc 882	Total
Black Hills		0.046	14	60	41	0.0632	56	171
PSCo		0.598	179	786	537	0.5127	452	1955
	IREA	0.017	5	22	15		0	43
CSU		0.08	24	105	72	0.0815	72	273
PRPA		0.063	19	83	57	0.1053	93	251
T-S		0.196	59	258	176	0.2373	209	702
	Total	1.000	300	1315	898		882	3396

Off-peak -
50% of Heavy Summer
Inc. Generation for 2030

Utility		Fraction of need	Gs(PV) 0	Gs(CS) 0	Gw 3590	Gc 882	Total
Black Hills		0.046	0	0	165	56	221
PSCo		0.598	0	0	2147	452	2599
	IREA	0.017			61		61
CSU		0.08	0	0	287	72	359
PRPA		0.063	0	0	226	93	319
T-S		0.196	0	0	704	209	913
	Total		0	0	3590	882	4472

IGD 3/21/2011

Table 5

3% forecast

Heavy Summer
Inc. Generation for 2030

Utility		Energy Fraction of need	Gs(PV) 399	Gs(CS) 1750	Gw 1195	Demand Fraction of Need	Gc 4903	Total
Black Hills		0.041	16	72	49	0.0405	199	336
PSCo		0.630	251	1103	753	0.6388	3132	5239
	IREA	0.013	5	23	16		0	43
CSU		0.081	32	142	97	0.0837	410	681
PRPA		0.055	22	96	66	0.0665	326	510
T-S		0.180	72	315	215	0.1705	836	1438
	Totals		399	1750	1195		4903	8247

Off peak -
50% of Heavy Summer
Inc. Generation for 2030

Utility		Fraction of need	Gs(PV) 0	Gs(CS) 0	Gw 4778	Gc 4903	Total
Black Hills		0.041	0	0	196	199	394
PSCo		0.630	0	0	3010	3132	6142
	IREA	0.013			62	0	62
CSU		0.081	0	0	387	410	797
PRPA		0.055	0	0	263	326	589
T-S		0.180	0	0	860	836	1696
	Totals		0	0	4778	4903	9681

IGD 03/21/2011

Table 6

Allocation of Convectional Generation

	Base MW	3% MW
PSCo		
Pawnee-40%	181	1253
Ft. St. Vrain-40%	181	1253
RMEC-10%	45	313
Spruce-10%	45	313
Total	452	3132
Black Hills		
ERZ 5-100%	56	199
Colo Spgs Utilities		
Nixon-100%	72	410
Platte River		
Rawhide-100%	93	326
Tri-State		
Lamar-100%	209	836
Total	882	4903

IGD 03/21/2011

Table 7

Year 2030

Key Transmission Lines	Base * Heavy Summer	Forecast Off Peak 50% of Heavy Summer	Projects Under Consideration	3% ** Heavy Summer	Forecast Off Peak 50% of Heavy Summer
1. St. Vrain – Ft. Lupton	2-230kV	2-230kV	Planned (Ault-Cherokee)	2-345kV	2-345kV
2. Pawnee-Missile Site	2-230kV	2-345kV	Planned (1-345 kV)	2-345kV	3-345kV
3. Missile Site-Smoky Hill	2-230kV	2-345kV	Planned (1-345 kV)	2-345kV	3-345kV
4. Missile Site-Daniels Park	1-230kV	1-345kV	Planned 1-345 kV	1-345kV	1-345kV
5. Missile Site-Big Sandy	2-345kV	3-345kV	Planned 2-345 Kv	3-345kV	4-345kV
6. Big Sandy-Burlington	2-345kV	3-345kV	Planned 2-345 Kv	3-345kV	5-345kV
7. Burlington-Lamar	2-345kV	2-345kV	Planned 2-345 Kv	2-345kV	2-345kV
8. Lamar-Boone-Comanche	1-345kV	3-345kV	Planned 2-345 Kv	2-345kV	4-345kV
9. Lamar- Vilas	1-230kV	2-345kV	Planned 2-345 Kv	1-230kV	2-345kV
10. Vilas-Gladstone	1-230kV	1-230kV	none	1-230kV	1-230kV
11. Comanche-Midway	1-345kV 2-345kV exist	1-345kV 2-345kV exist	none	1-345kV 2-345kV exist	2-345kV 2-345kV exist
12. Midway-Daniels Park/Waterton	3-345kV exist	3-345kV exist	Planned 1-345 kV	1-345kV 3-345kV exist	1-345kV 3-345kV exist
13. San Luis-Poncha	1-230kV 1-230kV exist	1-230kV 1-230kV exist	none	2-345kV 1-230kV exist	2-345kV 1-230kV exist
14. Poncha-Midway	2-230kV	2-230kV	none	2-345kV	2-345kV
15. San Luis-Calumet	2-345kV	2-345kV	Planned 2-230 kV	2-345kV	2-345kV
16. Calumet-Comanche	2-345kV	2-345kV	Planned 2-345 kV	2-345kV	2-345kV

*From Diagrams 1A-1 and 1A-2
**From Diagrams 1B-1 and 1B-2

Table 8

IGD 03/21/2011

2012-2030 Load Increment

Needed 600 MVA rated 230kV lines
for load serving*

	Base		3%	
Utility	Delta MW	Number of 230kV lines	Delta MW	Number of 230kV lines
Black Hills	185	2	287	2
PSCo	1500	4	4541	9
CSU	238	2	595	2
PRPA	308	2	473	2
T-S	694	2	1212	3

*Criteria - For load greater than 100 MW, needed lines plus one line to meet N-1 criteria. Assume existing system can absorb at least 100 MVA to cover the N-1.

IGD 03/21/2011

Table 9

Energy Resource Zones

Year 2030 – Base Case Forecast

Wind & Solar Generation – Nameplate Allocation in Zones
30% RES for all utilities by 2030

Total Wind: 4488 MW

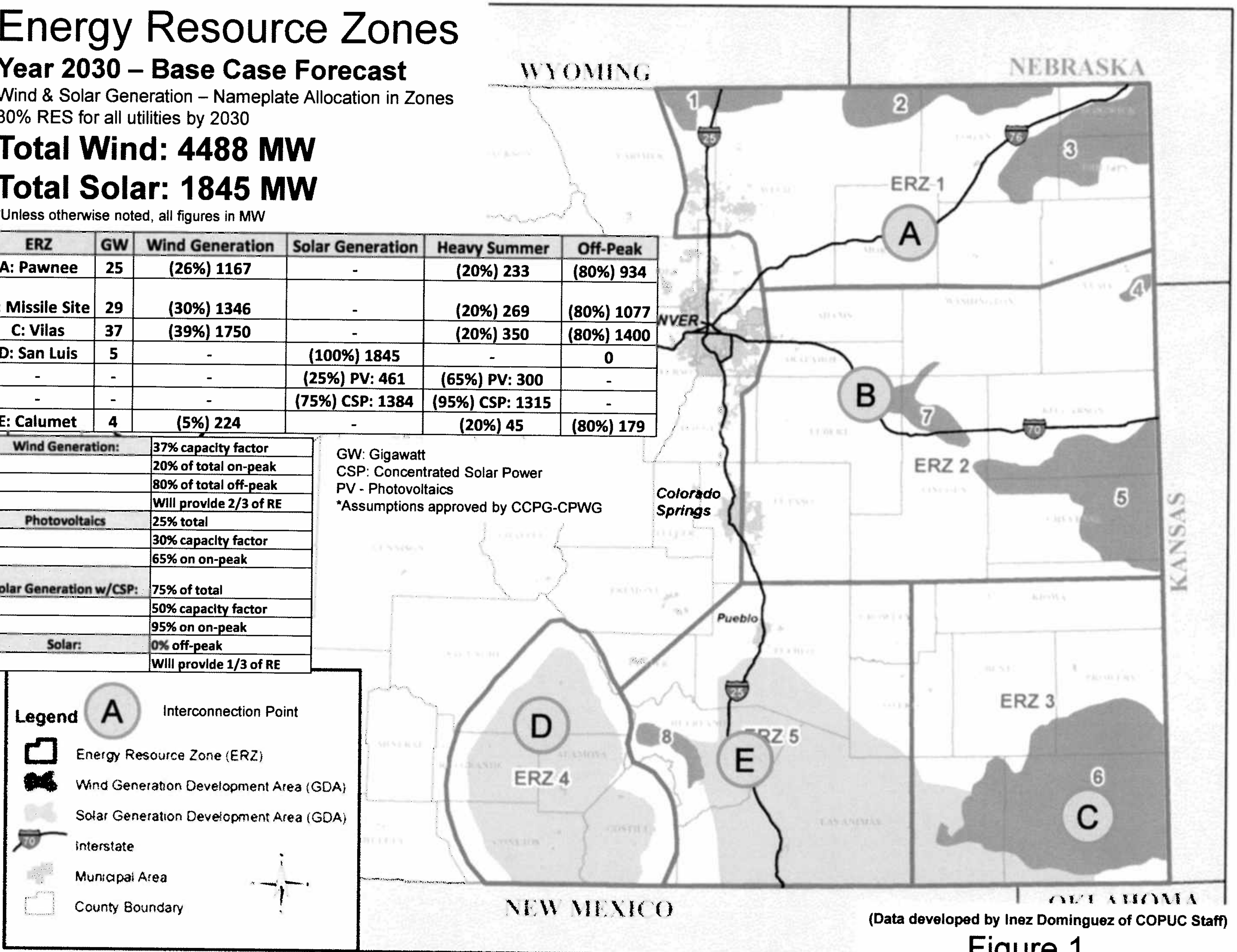
Total Solar: 1845 MW

*Unless otherwise noted, all figures in MW

ERZ	GW	Wind Generation	Solar Generation	Heavy Summer	Off-Peak
A: Pawnee	25	(26%) 1167	-	(20%) 233	(80%) 934
B: Missile Site	29	(30%) 1346	-	(20%) 269	(80%) 1077
C: Vilas	37	(39%) 1750	-	(20%) 350	(80%) 1400
D: San Luis	5	-	(100%) 1845	-	0
-	-	-	(25%) PV: 461	(65%) PV: 300	-
-	-	-	(75%) CSP: 1384	(95%) CSP: 1315	-
E: Calumet	4	(5%) 224	-	(20%) 45	(80%) 179

Wind Generation:	37% capacity factor
	20% of total on-peak
	80% of total off-peak
	Will provide 2/3 of RE
Photovoltaics	25% total
	30% capacity factor
	65% on on-peak
Solar Generation w/CSP:	75% of total
	50% capacity factor
	95% on on-peak
Solar:	0% off-peak
	Will provide 1/3 of RE

GW: Gigawatt
CSP: Concentrated Solar Power
PV - Photovoltaics
*Assumptions approved by CCPG-CPWG



(Data developed by Inez Dominguez of COPUC Staff)

Figure 1

Energy Resource Zones

Year 2030 – 3% Forecast

Wind & Solar Generation – Nameplate Allocation in Zones
30% RES for all utilities by 2030

Total Wind: 5973 MW

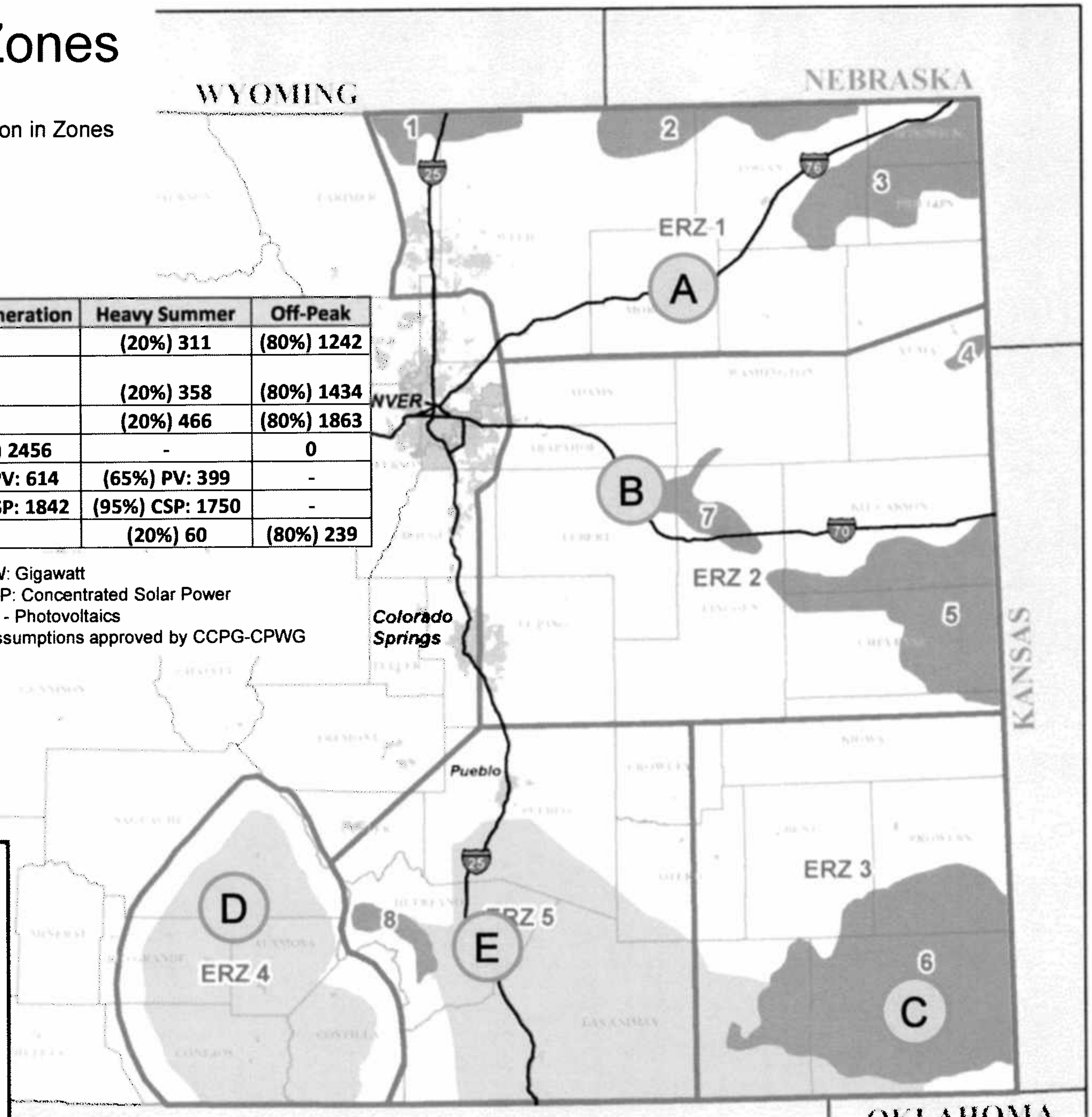
Total Solar: 2456 MW

*Unless otherwise noted, all figures in MW

ERZ	GW	Wind Generation	Solar Generation	Heavy Summer	Off-Peak
A: Pawnee	25	(26%) 1553	-	(20%) 311	(80%) 1242
B: Missile Site	29	(30%) 1792	-	(20%) 358	(80%) 1434
C: Vilas	37	(39%) 1792	-	(20%) 466	(80%) 1863
D: San Luis	5	-	(100%) 2456	-	0
-	-	-	(25%) PV: 614	(65%) PV: 399	-
-	-	-	(65%) CSP: 1842	(95%) CSP: 1750	-
E: Calumet	4	(5%) 299	-	(20%) 60	(80%) 239

Wind Generation:	37% capacity factor
	20% of total on-peak
	80% of total off-peak
	Will provide 2/3 of RE
Photovoltaics	25% total
	30% capacity factor
	65% on on-peak
Solar Generation w/CSP:	75% of total
	50% capacity factor
	95% on on-peak
Solar:	0% off-peak
	Will provide 1/3 of RE

GW: Gigawatt
CSP: Concentrated Solar Power
PV - Photovoltaics
*Assumptions approved by CCPG-CPWG



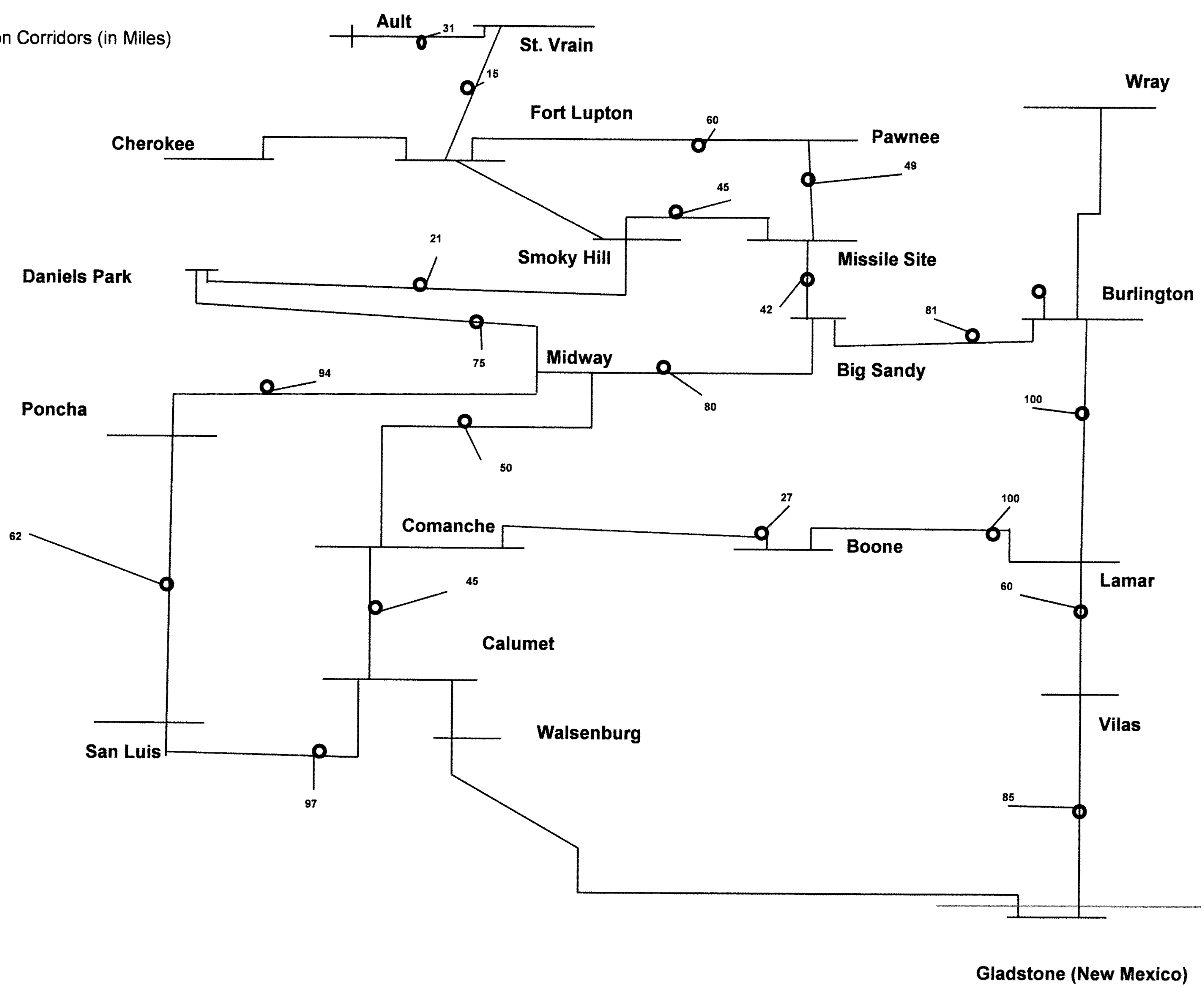
Legend
A Interconnection Point
Energy Resource Zone (ERZ)
Wind Generation Development Area (GDA)
Solar Generation Development Area (GDA)
Interstate
Municipal Area
County Boundary

(Data developed by Inez Dominguez of COPUC Staff)

Figure 2

Map 1

Transmission Corridors (in Miles)



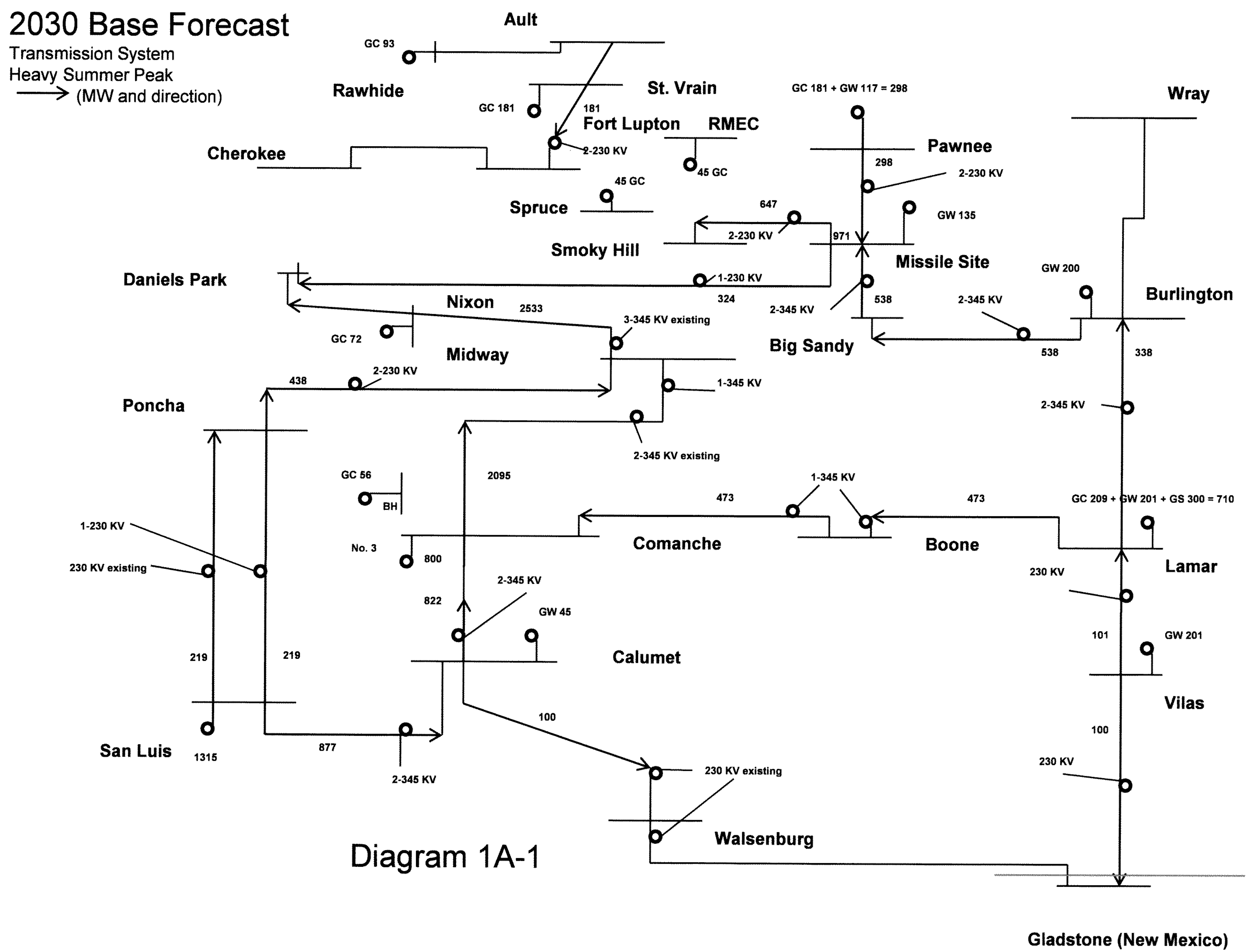

2030 Base Forecast
Transmission System
Heavy Summer Peak
(MW and direction)
Ault
GC 93
Rawhide
St. Vrain
GC 181
181
Fort Lupton
RMEC
2-230 KV
Cherokee
45 GC
45 GC
Spruce
GC 181 + GW 117 = 298
Wray
Pawnee
298
2-230 KV
GW 135
647
2-230 KV
971
Smoky Hill
Missile Site
Daniels Park
1-230 KV
324
Nixon
2533
2-345 KV
538
GW 200
2-345 KV
Burlington
3-345 KV existing
GC 72
Big Sandy
538
338
Midway
2-230 KV
438
1-345 KV
Poncha
2-345 KV
2-345 KV existing
GC 56
2095
BH
1-345 KV
473
473
GC 209 + GW 201 + GS 300 = 710
Comanche
Boone
No. 3
800
Lamar
230 KV
1-230 KV
230 KV existing
2-345 KV
822
GW 45
101
GW 201
219
219
Calumet
Vilas
100
100
230 KV
San Luis
1315
877
2-345 KV
230 KV existing
Walsenburg
Gladstone (New Mexico)

Diagram 1A-1

2030 Base Forecast

Transmission System
50% Heavy Summer Peak (Off Peak)
⟶ (MW and direction)

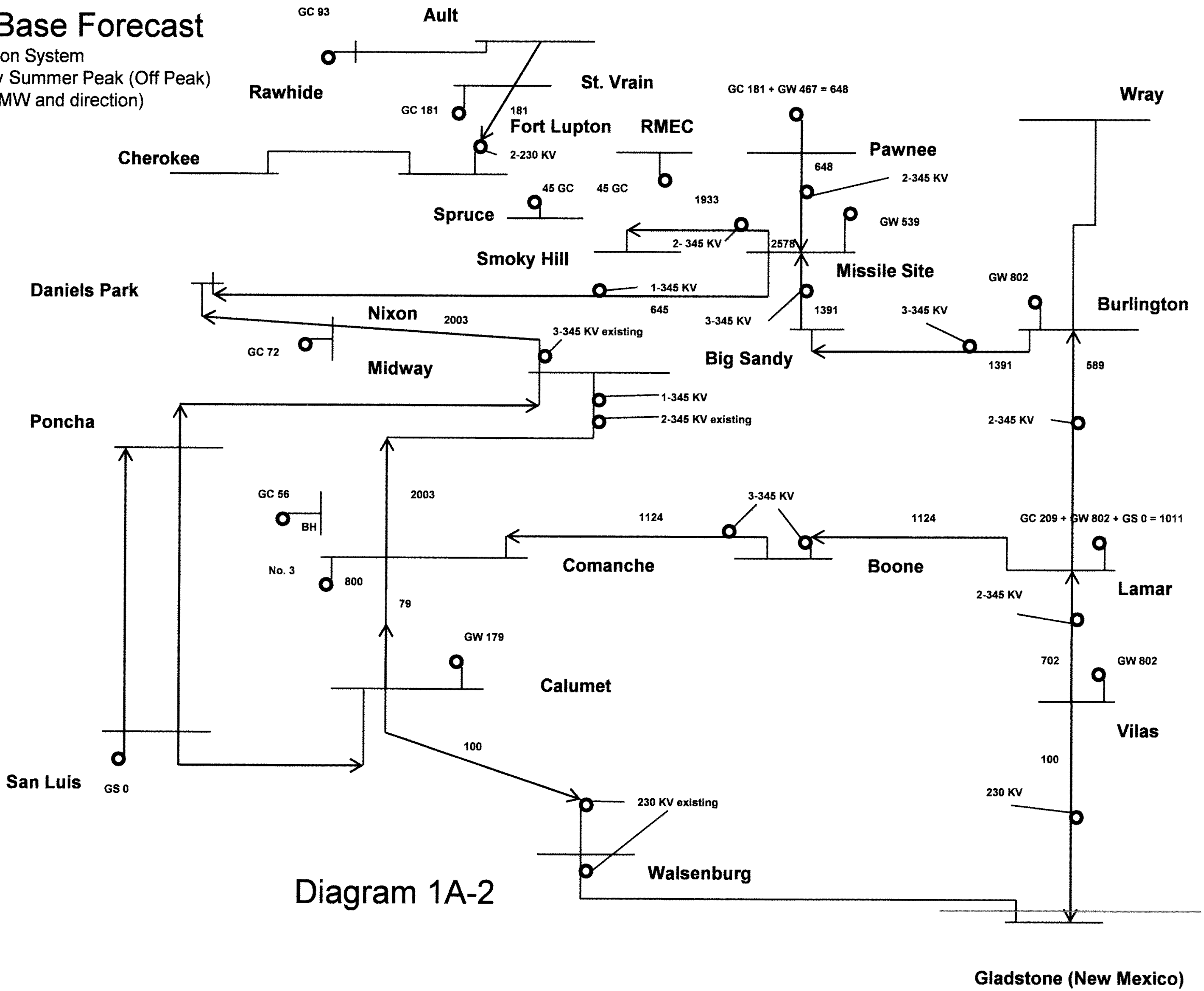


Diagram 1A-2

2030 3% Forecast

Transmission System
Heavy Summer Peak
→ (MW and direction)

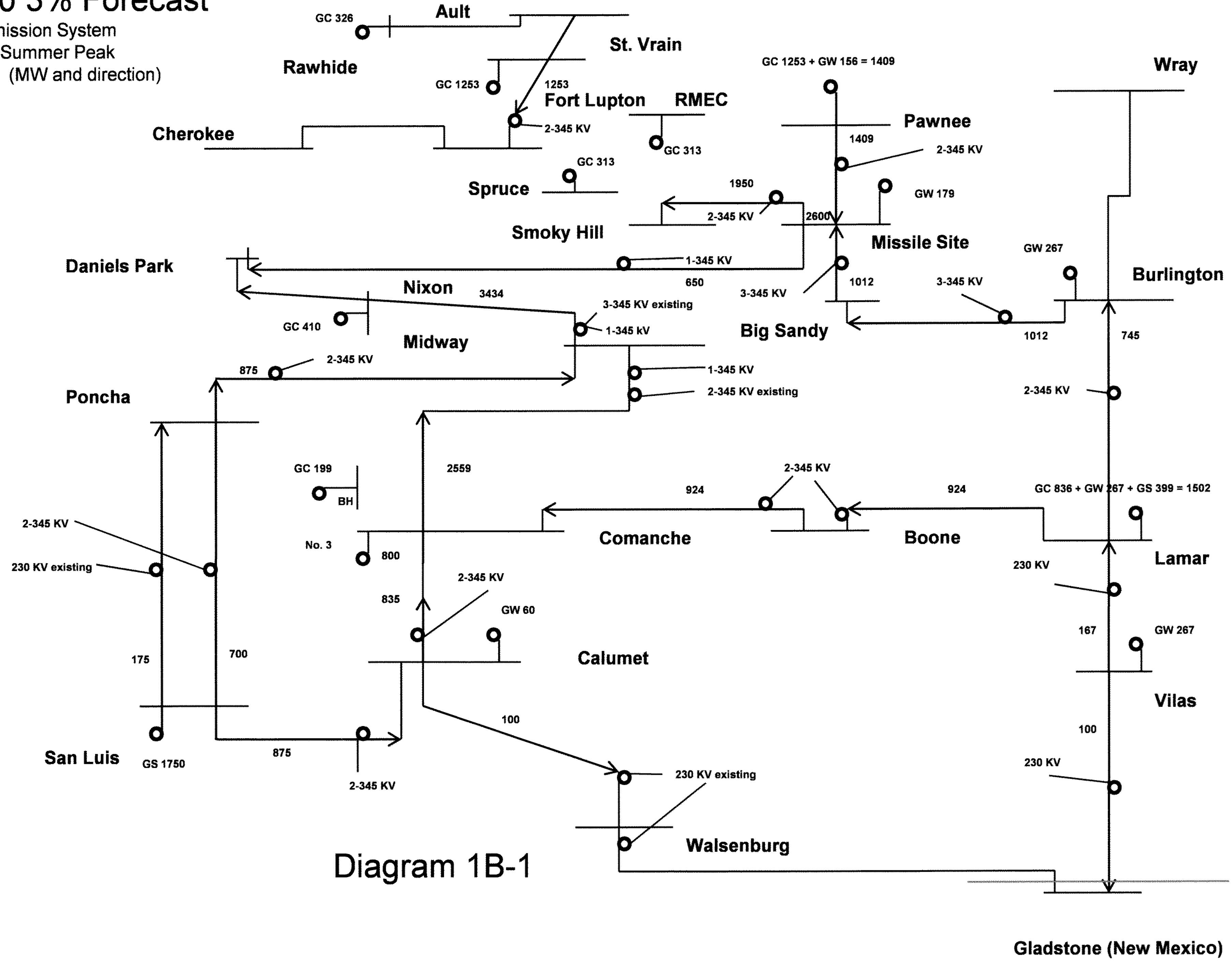


Diagram 1B-1

2030 3% Forecast

Transmission System
50% Heavy Summer Peak (Off Peak)
→(MW and direction)

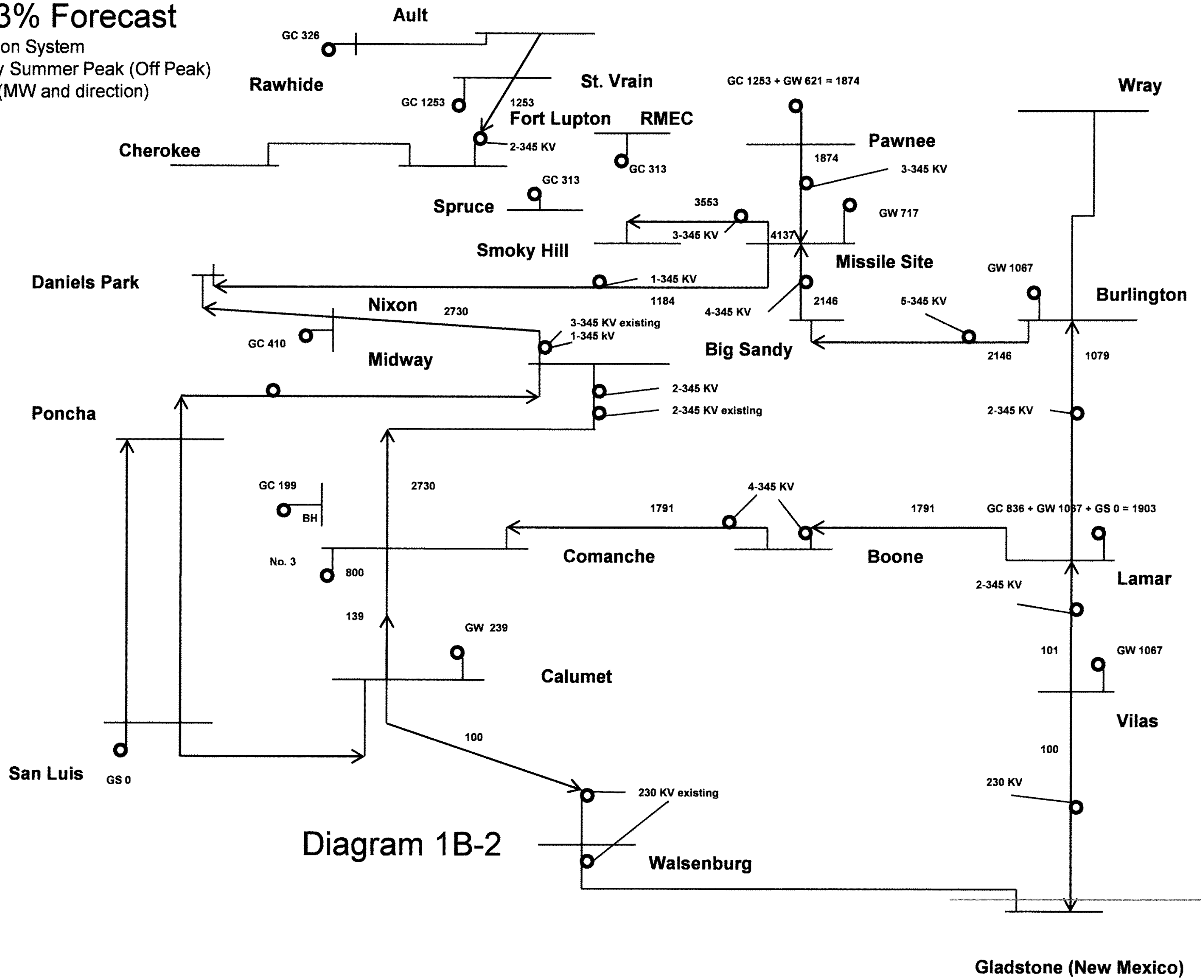


Diagram 1B-2