Technical Report

Energy Imbalance Market Options for Colorado

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Table of Contents

1. Executive Summary

The present study uses the WIS:dom®-P optimization model to investigate the energy imbalance market options available to Colorado and evaluate the benefits and costs of participating in each. The study also evaluates the impact of Colorado not joining any energy imbalance market and creating a state-wide Joint Dispatch Agreement (JDA) between all Colorado utilities and cooperatives. A unique component of the study is that it evaluates the benefits and costs over an evolving system from 2018 through 2040, rather than a single future year. The four scenarios considered in the analysis are:

(1) ***Business as Usual ("BAU"):*** *In this scenario Public Service Company of Colorado (PSCo), Black Hills Energy, Platte River Power Authority and Colorado Springs Utilities (JDA entities) as well as Intermountain Rural Electric Association and Holy Cross Energy join the Western Energy Imbalance Market (WEIM) operated by California Independent System Operator (CAISO) and members of the Tri-State cooperative (along with Basin Electric Power and the Western Area Power Administration) join the proposed Western Energy Imbalance Services (WEIS) market proposed by Southwest Power Pool (SPP).*

(2) ***All utilities and cooperatives in Colorado join WEIM ("West"):*** *In this scenario, all utilities and cooperatives within Colorado join the WEIM operated by CAISO.*

(3) ***All utilities and cooperatives in Colorado join WEIS ("East"):*** *In this scenario, all utilities and cooperatives within Colorado join the WEIS proposed by SPP.*

(4) ***Colorado forms a state-wide JDA ("CO-JDA"):*** *In this scenario, all utilities and cooperatives within Colorado sign a JDA and work together on sharing power and planning capacity expansion.*

WIS:dom®-P modeled the above four scenarios assuming optimal capacity expansion and economic dispatch, along with co-optimizing utility-scale generation with Distributed Energy Resources (DERs) – such as distributed solar (both rooftop and community solar), distributed storage (storage installed behind the 69-kV station) and demand side management (DSM). Transmission was allowed to grow in all scenarios.

Overall the study indicates that Colorado does better (in terms of retail rates, jobs, capacity, emissions) when it acts in a ***unified manner***. Splitting the utilities and moving to different EIM structures provides the least benefit to Colorado and exposes the state to competition from resources both east and west that encumbers the local resource pool. Further, Colorado brings enormous additional benefits to the region that it joins.

The "BAU" does provide benefits to Colorado compared with 2018 metrics, but are the least of all the studied scenarios. In the "BAU" scenario, Colorado retail rates reduce by $27.62/MWh by 2040 compared to 2018 values. In addition, by 2040 carbon emissions drop by 70.66% compared to 2018 as a result of 62% of the generation coming from carbon free sources. The "BAU" scenario also creates 61,528 additional jobs in the electric sector.

Results from the modeling show that ***the most beneficial*** scenario for Colorado retail customers is the ***"West"*** scenario, which results in the lowest retail rates driven by Colorado having access to a larger market to buy and sell energy and Colorado's wind and solar resource better positioned to take advantage of this market. In this scenario, retail rates reduced by an additional 0.84 ¢/kWh (a 30% reduction) compared to the “BAU” scenario. This scenario also resulted in lower total system costs compared to “BAU” scenario (cumulative savings of $0.8 billion compared to “BAU” scenario), the highest jobs created in the state of Colorado (75,375 additional full-time jobs compared to 2018) while resulting in the highest reduction in emission across all species of pollutants (reduction of additional 35 million tons of CO_2 compared to the “BAU” scenario). The emission reductions are driven by about 68.4% of the generation coming from carbon free energy sources (compared to 62% in the “BAU” scenario). In this scenario, Colorado deploys more wind (about 1,000 MW more wind compared to “BAU” scenario) and solar (about 500 MW more utility-scale solar compared to “BAU”) and more efficient utilization of these resources. Therefore, this scenario best positions Colorado to meet its renewable energy and emission reduction goals while reducing costs for consumers.

The “East” scenario also results in lower total system costs compared to the “BAU” scenario for the state of Colorado (cumulative savings of $1.2 billion compared to the “BAU” scenario). However, retail rates savings were lower than “West” scenario owing to having a smaller market compared to the WEIM as well as SPP having better wind resource than Colorado. In addition, higher transmission costs (upgrading DC ties) result in limited transmission growth that further hinder cost reductions. In the “East” scenario, retail rates reduced by an additional 0.69 ¢/kWh (a 25% reduction) compared to the “BAU” scenario. Emission reductions were also lower compared to the “West” scenario with CO_2 emissions reduced by additional 25 million tons compared to the “BAU” scenario with 64.6% of the generation coming from carbon free sources. The “East” scenario produced slightly lower jobs compared to the “West” scenario with additional 72,242 full-time jobs compared to 2018.

The “CO-JDA” scenario resulted in the lowest savings in retail rates compared to the “BAU” scenario with retail rates reduced by 0.35 ¢/kWh (a 12.7% reduction) compared to the “BAU” scenario. The reason for the lower retail rates savings is that in this scenario, the model attempts to make Colorado as self-sufficient as possible. This scenario had the lowest energy exchange with neighboring states compared to all scenarios. Thus, the model could not take advantage of selling excess energy to other regions when they need it. However, the “CO-JDA” scenario had the lowest system cost for the state of Colorado with cumulative savings of $1.91 billion compared to the “BAU” scenario. This scenario created 69,049 full-time jobs (fewer than the “West” or “East” scenarios, but more than the “BAU” scenario). It should be noted that this scenario still results in higher job creation and lower retail rates compared to the “BAU” scenario as the model takes advantage of the joint dispatch agreement among the utilities in Colorado to optimize energy sharing within the state. About 66.3% of the generation in the “CO-JDA” scenario came from carbon free energy sources.

The WIS:dom®-P technical documentation with detailed explanation of the model as well as details on creation of weather, climate and load datasets is available here.

The press release can be downloaded at:
https://www.vibrantcleanenergy.com/wp-content/uploads/2020/10/CO-EIM-Options-PressRelease.pdf

This study report can be downloaded at:
https://www.vibrantcleanenergy.com/wp-content/uploads/2020/10/CO-EIM-Options-Report.pdf

The accompanying presentation can be downloaded at:
https://www.vibrantcleanenergy.com/wp-content/uploads/2020/10/CO-EIM-Options-Presentation.pdf

The WIS:dom®-P model output spreadsheets can be downloaded at:
https://www.vibrantcleanenergy.com/wp-content/uploads/2020/10/CO-EIM-Options-Spreadsheets.zip

2. Modeling Results

2.1 Study Description

In the present study, Vibrant Clean Energy (VCE®) looked into the various energy imbalance market options available to Colorado and whether they provide any potential benefits in terms of system costs, retail rates to customers, emission reductions or more efficient serving of load. A unique component of the study is that it evaluates the benefits and costs over an evolving system from 2018 through 2040, rather than a single future year.

Several utilities in Colorado, namely, Public Service Company of Colorado (PSCo), Black Hills Cooperation, Colorado Springs Utilities, Platte River Power Authority have a Joint Dispatch Agreement (JDA). The JDA entities are currently planning to join the Western Energy Imbalance Market, which is in operation over much of the western United States and administered by California Independent System Operator (CAISO). In contrast, Tri-State and its entities (along with Basin Electric Power and the Western Area Power Administration are currently planning to join the proposed Western Energy Imbalance Service (WEIS), administered by the Southwest Power Pool (SPP).

The utilities in Colorado joining larger energy markets will bring economic benefits. The present study models the impacts of the various utilities in Colorado joining the larger energy markets and its effects on system costs, retail rates, capacity buildout and emissions. In addition, this study models three additional scenarios to investigate the impacts of decisions made by Colorado as a unified entity and not splitting up into two different energy markets. The scenarios modeled in this study are as follows:

(1) ***Business as Usual ("BAU"):*** *This scenario models the current plans of the JDA entities to join the WEIM and Tri-State coop to join the proposed WEIS. It is assumed that some of the smaller entities such as Holy Cross Energy (HCE) and Intermountain Rural Electric Association (IREA) also take part in the WEIM along with the JDA entities.*

(2) ***Colorado joins WEIM ("West"):*** *This scenario models all the utilities in Colorado join the WEIM and set up joint dispatch agreements among themselves within Colorado. This scenario assumes that all entities in the WEIM take advantage of the imbalance market and optimize capacity expansion and transmission planning accordingly.*

(3) ***Colorado joins WEIS ("East"):*** *This scenario models all the utilities in Colorado joining the WEIS and set up joint dispatch agreements among themselves within Colorado. This scenario assumes that all entities in the WEIS take advantage of the imbalance market and optimize capacity expansion and transmission planning accordingly.*

(4) ***Colorado creates state-wide JDA ("CO-JDA"):*** *This scenario models all utilities in Colorado creating a joint dispatch agreement and working together to create an energy imbalance market limited to Colorado. In this scenario, all utilities in Colorado coordinate capacity expansion and transmission planning.*

To model the above scenarios, VCE® used its flagship modeling suite WIS:dom®-P, which is a state-of-the-art combined capacity expansion and production cost model. For all scenarios in this report, WIS:dom®-P performed optimal capacity expansion and production cost while co-optimizing utility-scale generation, storage, transmission along with distributed energy resources (DERs). The modeling was initialized using 2018 generation and transmission datasets and the model was executed through 2040 with results outputted every 5 years from 2020. Detailed description of the WIS:dom®-P model can be found in the WIS:dom®-P technical documentation[1].

For each scenario considered, the economic impacts of the optimal capacity expansion and production costs decisions such as total system costs, transmission and distribution costs, retail rates, jobs created (and more) are computed and tracked. In addition, the model calculates all species of pollutants and change in emissions over the investment periods. Description of the standard inputs to the model in terms of generator input datasets is described in Section 3.1. Descriptions of wind and solar resource as well as siting potential are in Section 3.3. Finally, Section 3.4 presents in detail all the standard inputs that go into the WIS:dom®-P model such as costs, policy mandates, jobs etc.

As part of the optimal capacity expansion, WIS:dom®-P has to ensure it meets grid reliability constraints through meeting the planning reserve margins specified by the North American Electric Reliability Corporation (NERC) in addition to having a 7% load following reserve at all times. Section 2.9 discusses the details on how capacity value of both thermal and VRE generation is estimated by the model.

In terms of transmission cost allocation, the model divides the cost of new transmission between the entities connected by the ratio of their respective loads. This method of allocating transmission costs represents a more conservative approach for transmission cost allocation. If the EIM agreements result in greater regionalization in the allocation of the transmission cost, the outcomes for utilities in Colorado are expected to improve further as transmission costs are distributed over a larger number of entities.

[1]https://vibrantcleanenergy.com/wp-content/uploads/2020/08/WISdomP-Model_Description(August2020).pdf

2.2 Model Setup

To model the impacts of decisions made by utilities in Colorado, WIS:dom®-P was setup to model the whole (US portion of) Western Electricity Coordinating Council (WECC) along with the SPP region. Within Colorado, WIS:dom®-P was run at utility-scale resolution in order to resolve the capacity expansion and transmission planning decisions made by individual utilities as well as their impacts on cost of serving load and all the other metrics. In addition, New Mexico and Wyoming were split up into two regions each to resolve the portions of each state planning to join either the WEIM or WEIS. The remainder of the model domain was modeled at state-level resolution. The SPP and CAISO regions were modeled at state-level approximations with only loads and generation within the states modeled included. Figure 2.1 shows the region of the contiguous United States (CONUS) modeled in this study. The region shaded in black is not part of the model domain.

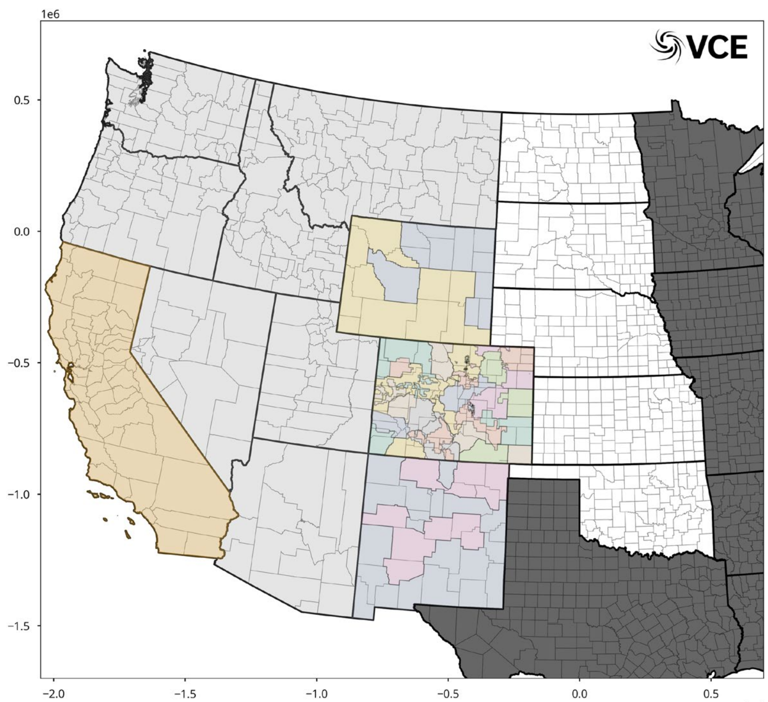


Figure 2.1: WIS:dom®-P modeling domain. The region shaded in black is not part of the model domain.

Within Colorado, transmission and existing installed generation is aggregated to utility level resolution including generation contracted or owned outside of each utility's geographic boundaries. In addition, load shapes, wind/solar resource profiles, transmission line ratings and losses, heat-rate profiles, etc. are also aggregated to utility level resolution. Load profiles for utilities in Colorado were obtained either through publicly available data or through the respective utilities.

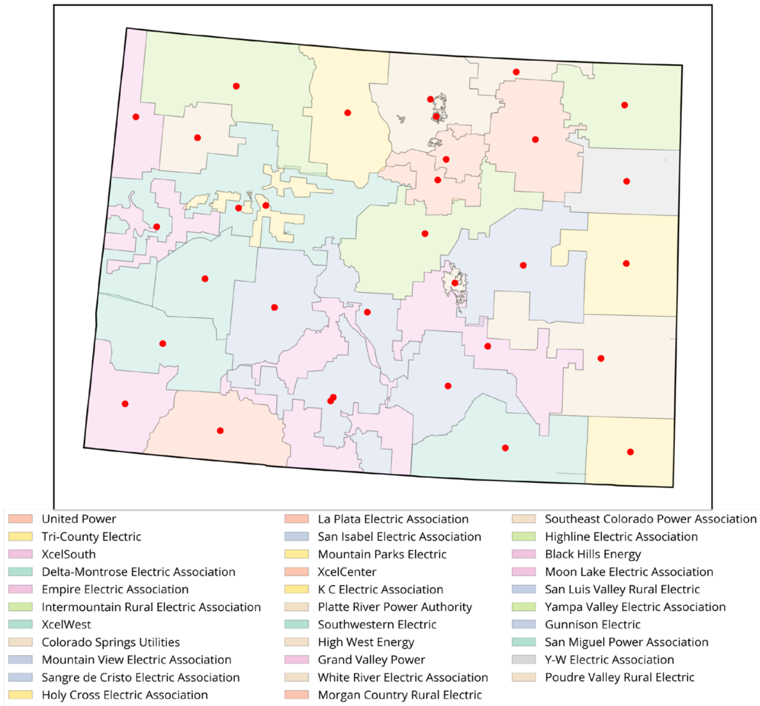


Figure 2.2: Utility regions in Colorado

Finally, the model is executed in two stages (1) outer run and (2) inner run. The outer run is performed at state level resolution for the full model domain including Colorado. The inner run uses the results from the outer run as boundary conditions along with specified tolerances. This framework allows the inner run to solve much faster compared to directly running the higher resolution model. For the inner run, the model re-solves over all of Colorado for transmission and capacity buildout and siting. The capacity expansion portion of the WIS:dom®-P model is slightly more constrained (bound to the outer run solution) over WY and NM and re-solves the regions joining either WEIM or WEIS in these states. The capacity expansion portion of the WIS:dom®-P model has the most stringent constraints from the outer run in rest of the states in the model domain. This framework was designed to mimic real-life dynamics where decisions made in Colorado are quite unlikely to create major impacts on capacity buildout decision in the rest of the WECC or SPP.

2.3 Transmission and Energy Exchange

WIS:dom®-P starts with transmission topology at the nodal resolution as shown in Fig. 3.2. The nodal resolution topology is then aggregated to the resolution required for the modeling. For the outer run, the nodal level topology was aggregated to state-level resolution as shown in Fig. 2.2.

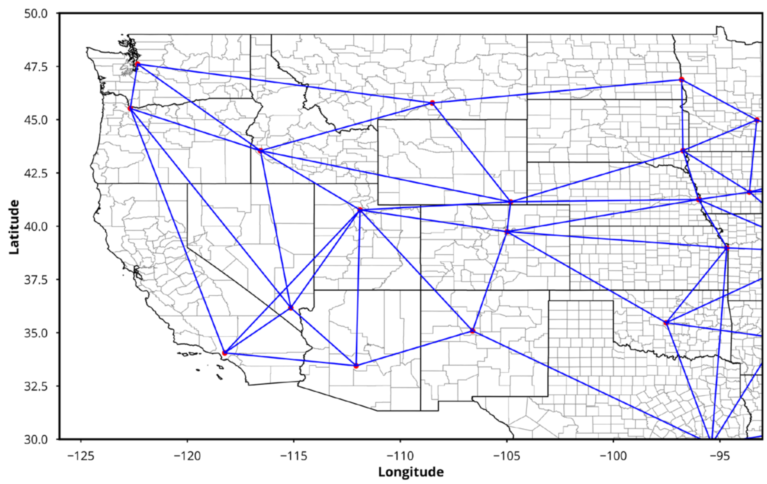
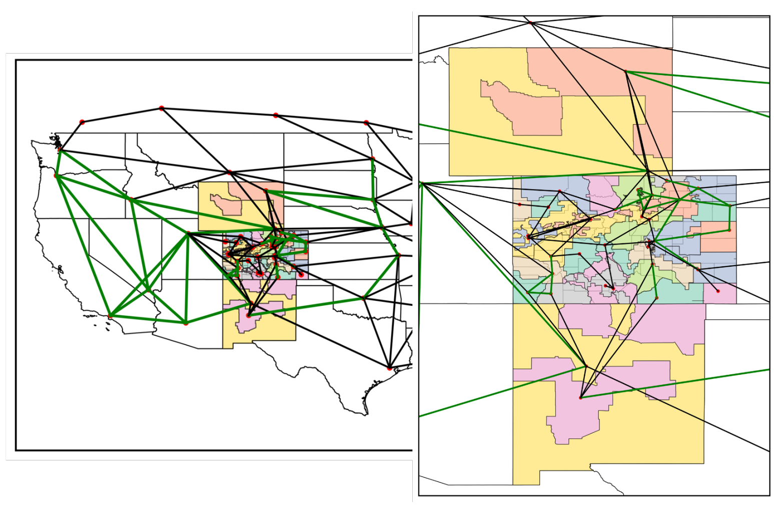


Figure 2.2: State-level aggregated transmission

The transmission topology for the inner run where Colorado is modeled at utility-level resolution and WY and NM are split into two parts each (one joining WEIM and other joining WEIS) is shown in Fig. 2.3. The lines are color coded based on whether wheeling charges are applied on the lines. Green lines have no wheeling charge and black lines have a wheeling charge of $8 / MWh[2]. It is assumed that transmission between members belonging either to the JDA or the Tri-State coop will not impose wheeling charges on one another. In addition, no wheeling charges are assumed between entities which are part of either of the energy imbalance markets.



[2] Chang et al, Joint Dispatch Agreement Energy Imbalance Market Participation Benefits Study. https://brattlefiles.blob.core.windows.net/files/19235_joint_dispatch_agreement_energy_imbalance_market_participation_benefits_study.pdf

Figure 2.3: Transmission topology and transmission wheeling charges in 2018 for model initialization.

In 2020, Montana joins the WEIM and Colorado Springs utilities joins the JDA in Colorado. The transmission and wheeling charge flags are updated to reflect this change in the model starting 2020. As seen in Fig. 2.4, Montana is now connected to WEIM states with an RTO line (green). In addition, the JDA entities as well as Yampa Valley Electric Association, HCE and IREA join the WEIM, utility regions covered by the JDA entities also are able to access the WEIM region through an RTO line.

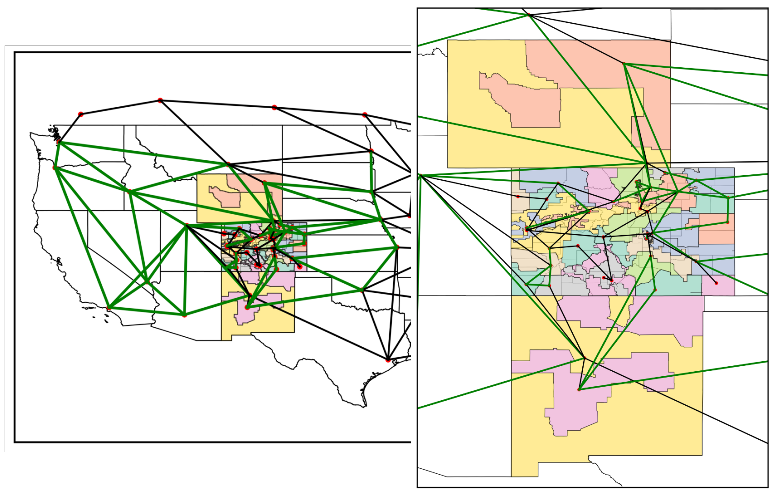


Figure 2.4: Transmission and wheeling charge flags for the "BAU" scenario in 2020.

2.3.1 Colorado joins the WEIM Scenario ("West")

When all of Colorado joins WEIM, it is assumed that all utilities within Colorado as members of the WEIM work together on capacity expansion planning as transmission buildout. As seen from Fig. 2.5, connections to portions of Wyoming and New Mexico that are part of the WEIM become RTO lines (no wheeling charges) as well as all the lines within Colorado.

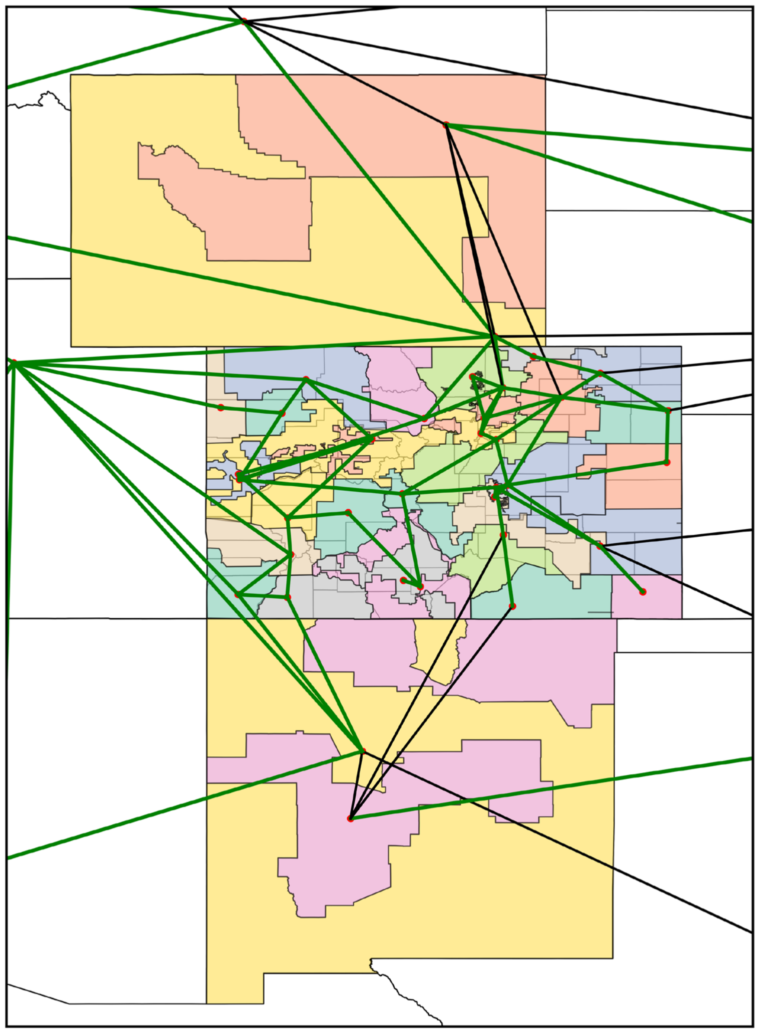


Figure 2.5: Transmission and wheeling charge flags for the "West" scenario in 2020.

2.3.2 Colorado joins WEIS Scenario ("East")

When Colorado joins the proposed WEIS, it is assumed that all utilities in Colorado work together with other members of WEIS in SPP and in Wyoming and New Mexico. As seen from Fig. 2.6, connections to regions in Wyoming and New Mexico planning to join WEIS become RTO lines in addition to all lines within Colorado.

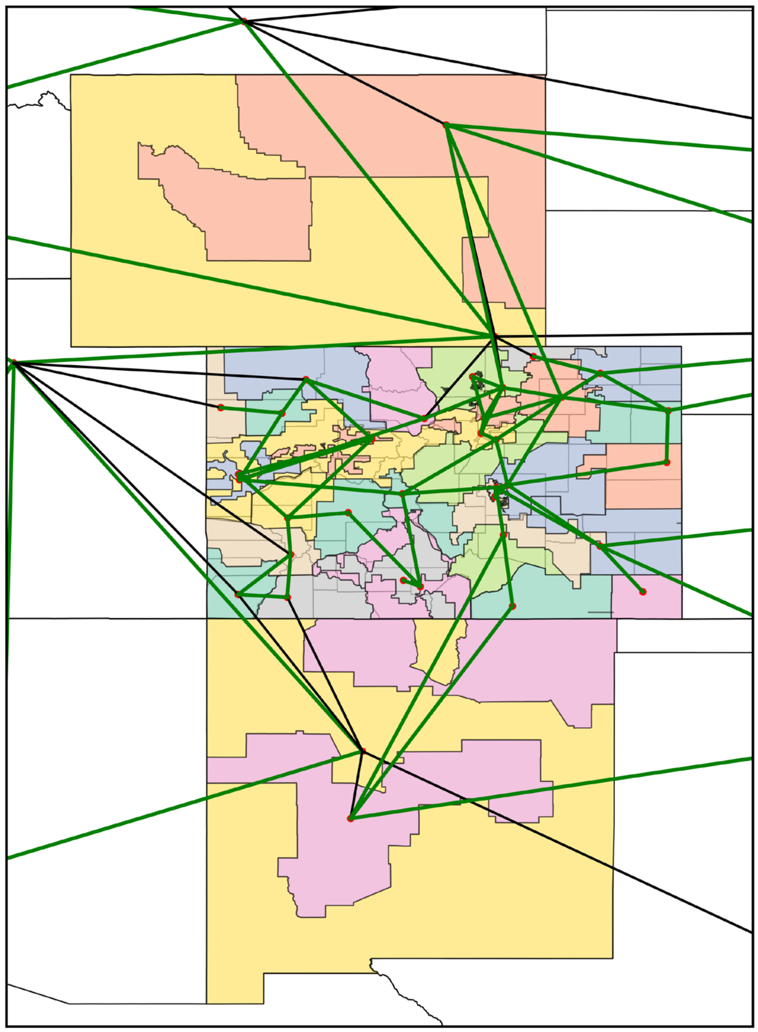


Figure 2.6: Transmission and wheeling charge flags for the "East" scenario in 2020.

2.3.3 Colorado forms state-wide JDA ("CO-JDA"):

In this scenario, Colorado creates a state-wide joint dispatch agreement within the state borders. This JDA requires all utilities within Colorado to allow free transfer of electricity over the transmission network as well as all entities in Colorado work together to optimize capacity expansion and dispatch of generation to meet load.

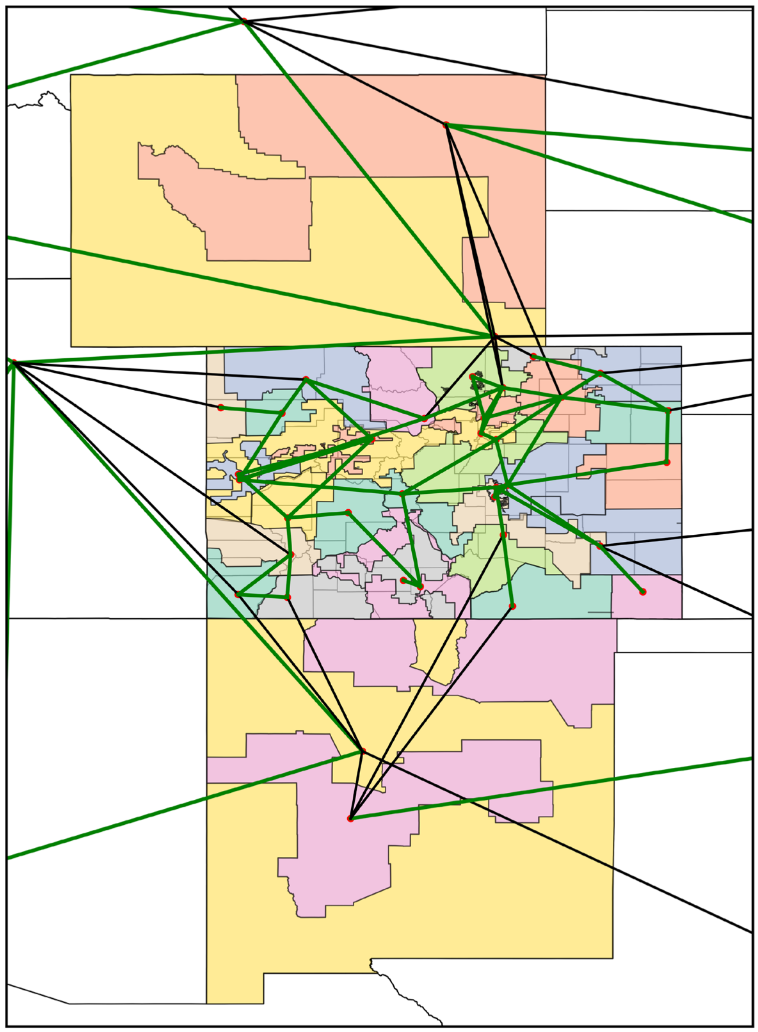


Figure 2.7: Transmission and wheeling charge flags for the "CO-JDA" scenario in 2020.

2.4 Impact of Business as Usual

As a consequence of the JDA entities joining the WEIM and Tri-State cooperative joining the proposed WEIS, there are substantial economic benefits to Colorado and the two EIM regions. It is seen that the annual total resource costs for the WECC+SPP domain reduce by about 25% on a net present value basis by 2040. These savings come from a combination of optimal capacity expansion to include cheap renewable energy sources as well as efficient use of generated energy through the large energy imbalance market. As a result, the average retail rates for the WECC+SPP region drop about $27.73/MWh by 2040, a 28.3% reduction.

Colorado does benefit from all the saving occurring over the WECC+SPP region. As shown in Figure 2.8, the annual total resource costs in Colorado reduce by about 20%, which leads to a $27.61/MWh drop in retail rates by 2040. The reduction in retail rates comes not only from lowering costs due to cheap renewable generation, but also revenues from selling into the energy imbalance market.

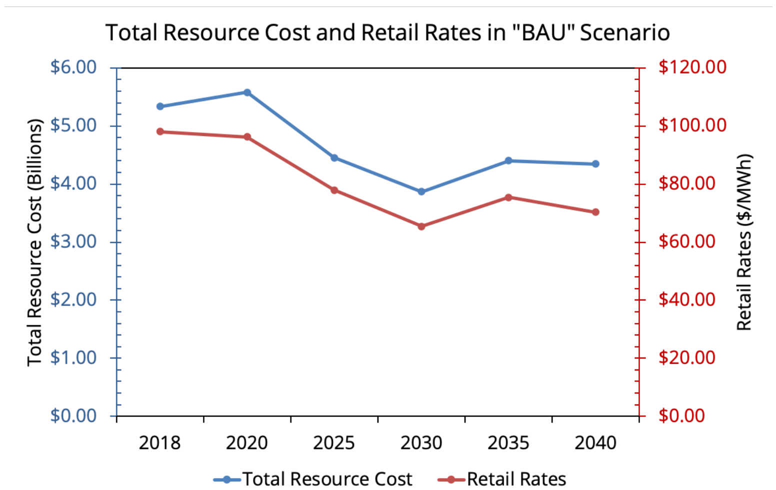


Figure 2.8: Change in total resource costs and retail rates over the WECC+SPP domain in the "BAU" scenario.

In the "BAU" scenario, there is a shift from reliance on thermal generation to meet demand to mostly clean generation with more than 50% coming from wind and solar (see Fig. 2.9). In Colorado, 62% of the generation comes from carbon free sources. Roughly 37.7 GW of storage gets installed by 2040 with an average duration of 8 hours. The model almost completely retires coal generation by 2030 and natural gas combustion turbines completely retire by 2035. Storage takes on the role of fast ramping generation to meet periods of peak demand resulting in lower system costs and lower emissions.

The "BAU" scenario also sees installation of natural gas combined cycle with Carbon Capture and Sequestration (CCS) units to meet the various greenhouse gas (GHG) and clean energy mandates of various states in WECC. Distributed solar makes up about 45% of the total solar installed which helps reduce retail rates for consumers while also helping reduce distribution system upgrade costs. By 2040, almost 80% of the generation on the WECC+SPP grid is emissions free.

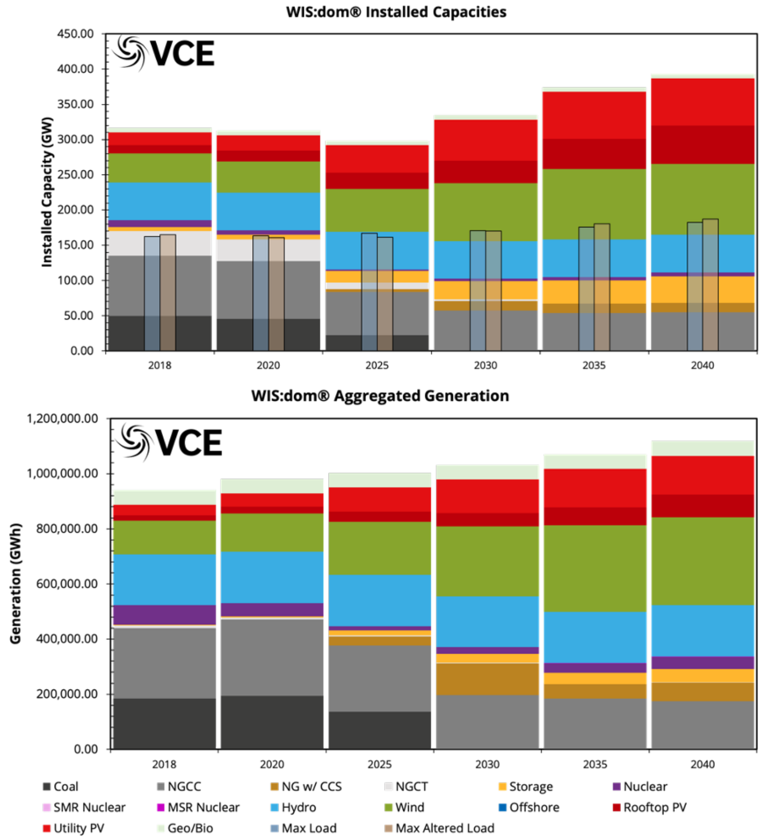


Figure 2.9: WIS:dom® installed capacities and aggregated generation in the "BAU" scenario.

As a result of retiring all the coal and natural gas combustion turbines, emissions in the electric sector are seen to reduce significantly by 2040 (see Fig. 2.10). By 2040, carbon dioxide emissions reduce by 70%, while SO_2, PM2.5 and PM10 are seen to go almost to zero in the electric sector. It is seen that the rate of decline in emissions is faster initially up to 2030, exceeding the reductions required by GHG and clean energy mandates. After 2030, the rate of emission reductions slows down as the fraction of renewables in the generation mix saturates to optimal levels and generation from CCS reduces due to expiring of 45Q tax credits (no capacity is retired however).

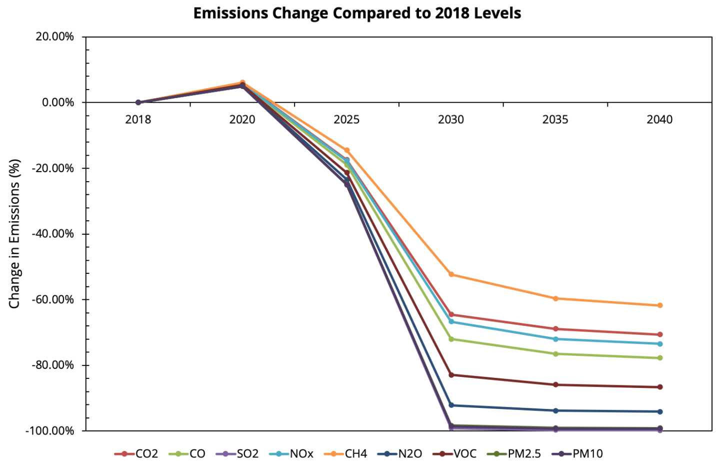


Figure 2.10: Change in emission compared to 2018 levels in the "BAU" scenario.

The capacity mix changing from a largely fossil generation to largely variable renewable energy (VRE) generation along with transmission buildout results in almost doubling the number of jobs in the electric sector for the WECC+SPP region as shown in Fig. 2.11. By 2040, about 700,000 new jobs with respect to 2018 are created in the WECC+SPP region (see Fig. 2.11, top panel). A significant portion of these jobs are in the solar industry, followed closely by the transmission and distribution sector.

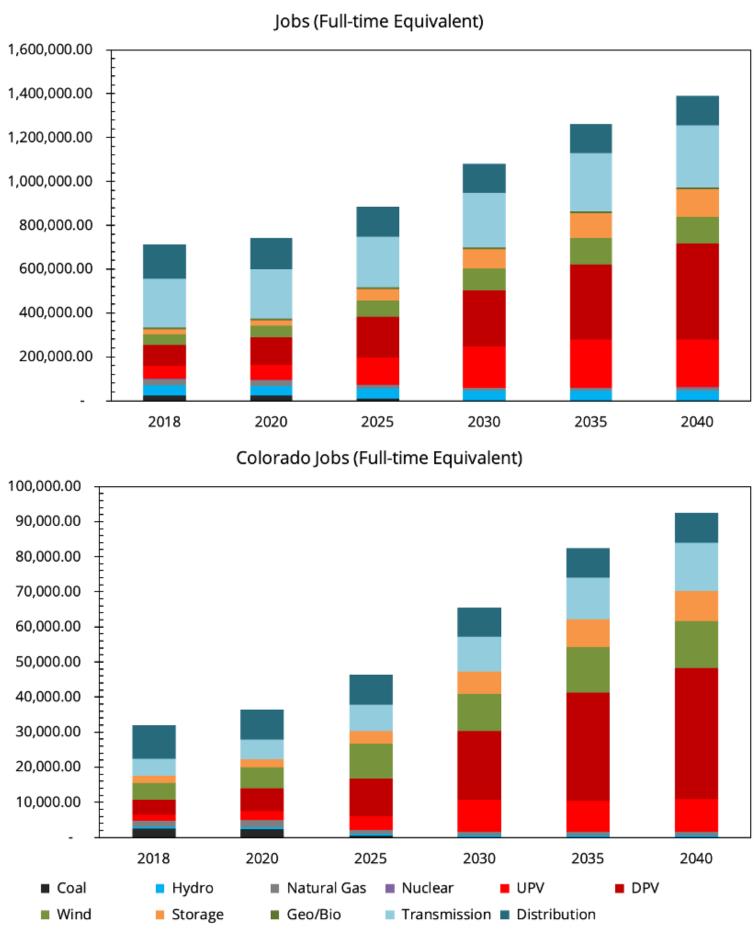


Figure 2.11: Jobs created in the electric sector in the "BAU" scenario.

Job growth rate in Colorado (Fig. 2.11, bottom panel) is seen to be faster than the rest of the WECC+SPP region. Jobs in Colorado are seen to triple from 2018 levels, led by the distributed solar sector. The massive growth seen in the distributed solar industry not only creates jobs, but also helps offset costs associated with upgrading distribution system infrastructure while meeting load using renewable generation.

Colorado is seen to follow similar trends as the rest of the WECC+SPP domain in terms of capacity buildout. All coal generation is seen to retire by 2030, and by 2040 only combined cycle natural gas remains along with CCS as the sole fossil fuel generation (see Fig. 2.12) making 62% of the generation carbon free. Most of the generation in Colorado is controlled by PSCo as it is the largest utility serving the largest load in the state. Some form of VRE generation is installed within each Colorado utility's service territory. Wind is seen to be the most prolific with 10.4 GW of onshore wind installed. The majority of new wind is sited in the north-east quadrant of the state. There is about 7.2 GW of solar installed in Colorado of which about 61% (4.4 GW) is distributed solar (rooftop and community solar).

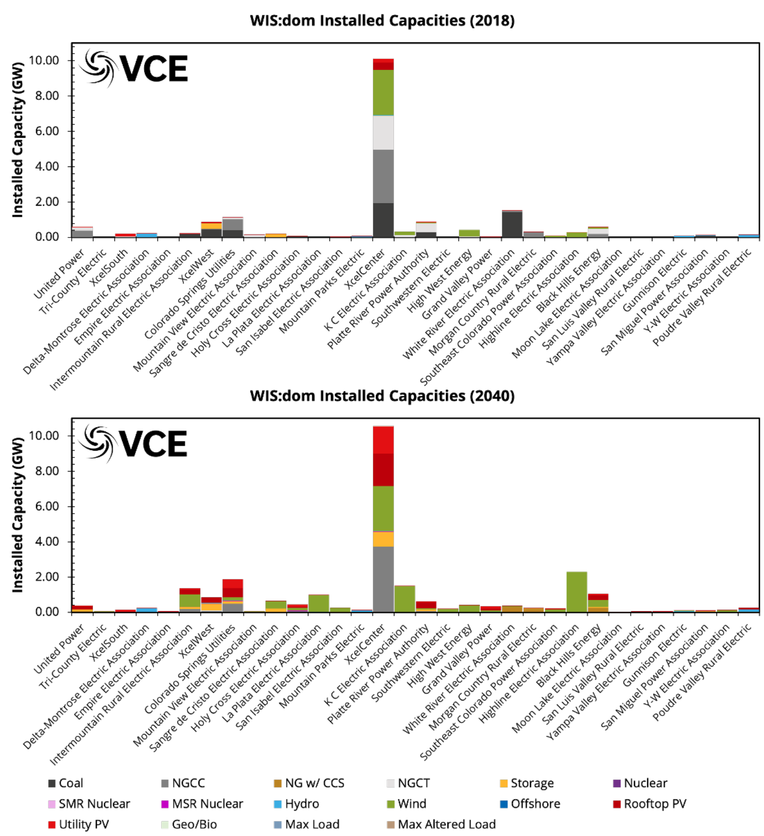


Figure 2.12: Installed capacities in Colorado in 2018 (top) and 2040 (bottom) in the "BAU" scenario.

The preference within Colorado to install distributed generation is seen in storage installations as well. It is seen that 73% of the storage installed is distribution scale (behind the 69-kV bus) as shown in Fig. 2.13. As a result of the DER deployment, the distribution system sees an annual savings of about $4.2 million dollars resulting in cumulative savings of $84 million by 2040 in deferred distribution system upgrades.

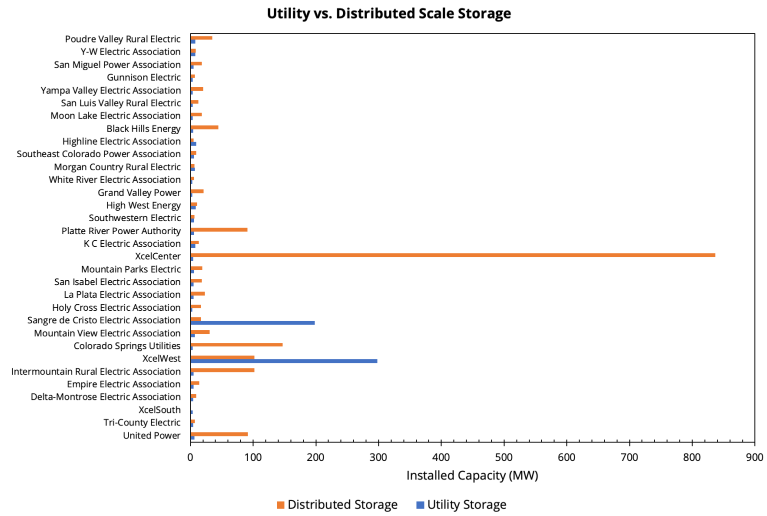


Figure 2.13: Utility scale and distribution scale storage installed by utilities in Colorado in the "BAU" scenario by 2040.

Modeling the co-optimization of utility-scale and distribution-scale resources is discussed in detail in Section 1.9.2 of the WIS:dom®-P technical documentation. Briefly, when considering any utility scale capacity buildout to meet load, WIS:dom®-P includes the cost of distribution system upgrades requires to ensure the new generation can be routed to the load. WIS:dom®-P then considers if it is more cost effective to deploy DER technologies behind the 69-KV node (taking into account challenges such as back-flow and changes to peak-demand) and defer distribution system upgrades.

Figure 2.14 shows the original load duration curve and the DER modified load duration curve for Colorado. It is seen that the peak load is reduced by 2292 MW (a 20% reduction) and much flatter compared to the original load duration curve. As a result of this reduction in peak load, the need for generating capacity to meet the low duration high magnitude peak is reduced resulting in lower system costs.

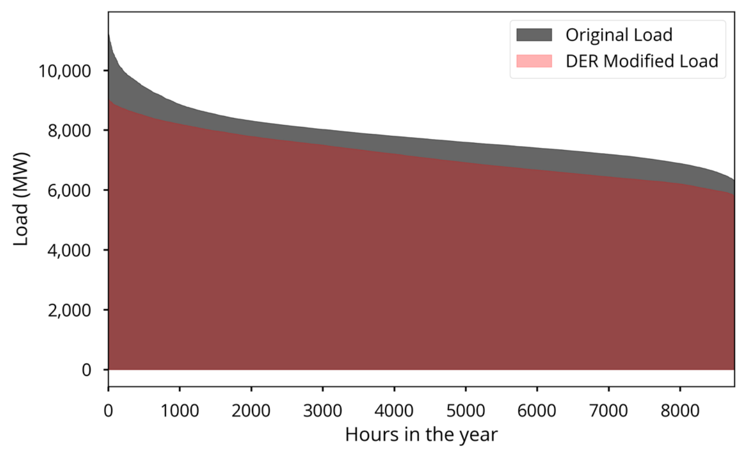


Figure 2.14: The original load during curve versus the DER modified load duration curve for Colorado by 2040 in the "West" scenario.

2.5 Economic Impacts of EIM Choices

It is found that when Colorado joins either of the energy imbalance markets (WEIM or WEIS), there are substantial economic benefits to the WECC+SPP region in addition to those already attained in the “BAU” scenario. As seen from Fig. 2.15, the “West” scenario saves an additional $2.88 billion cumulatively by 2040, compared to an additional $2.17 billion in savings from the “East” scenario. The “CO-JDA” scenario creates the least additional savings at $0.32 billion additional savings by 2040.

The “West” scenario also results in highest savings in terms of retail rates to customers. By 2020, the “West” scenario results in an additional $4.3/MWh reduction in retail rates which increases to $5.5/MWh by 2035 before settling at $5.64/MWh (a 20% addition to savings already achieved in the “BAU” scenario). All scenarios are seen to create roughly 700,000 additional jobs compared to 2018 levels in the electric sector.

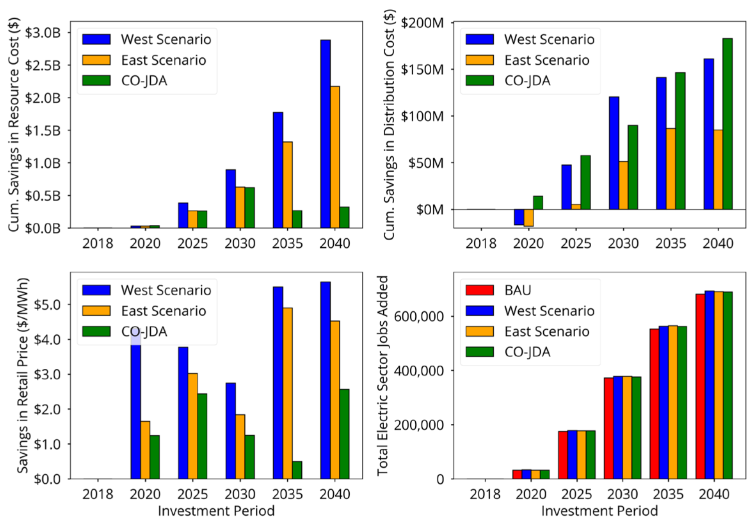


Figure 2.15: Differences in total resource costs (top left), distribution costs (top right), retail rates (bottom left) and jobs created (bottom right) for WECC+SPP in the various scenarios compared to the BAU scenario.

The changes in total resource costs, distribution costs, retail rates and jobs in Colorado for the various scenarios are shown in Fig. 2.15. As seen from Fig. 2.16, Colorado has the highest savings in total resource costs in the “CO-JDA” scenario with almost $1.91 billion saved cumulatively by 2040 in addition to the savings from the “BAU” scenario. However, the “CO-JDA” scenario has the lowest savings in retail rates due to the model attempting to make Colorado as self-sufficient as possible and minimizing energy exchange with its neighbors. The “East” scenario results in additional savings of $1.2 billion while the “West” scenario results in the lowest additional savings at $0.8 billion in resource cost, but has the highest savings in retail rates through utilizing the imbalance market to trade energy.

In terms of distribution costs, it is seen that “West” scenario has slightly higher distribution costs with respect to the “BAU” scenario, while the “East” and “CO-JDA” scenario end up with approximately the same amount of additional savings in distribution costs of about $20 million. However, when it comes to retail rates, it is seen that the “West” scenario results in the lowest retail rates with an additional reduction of $8.44/MWh (a 30% additional savings compared to savings already achieved in "BAU"). The "East" scenario is close behind with an additional \$6.93/MWh savings in retail rates, while the "CO-JDA" results in lowest additional savings in retail rates of about \$3.5/MWh.

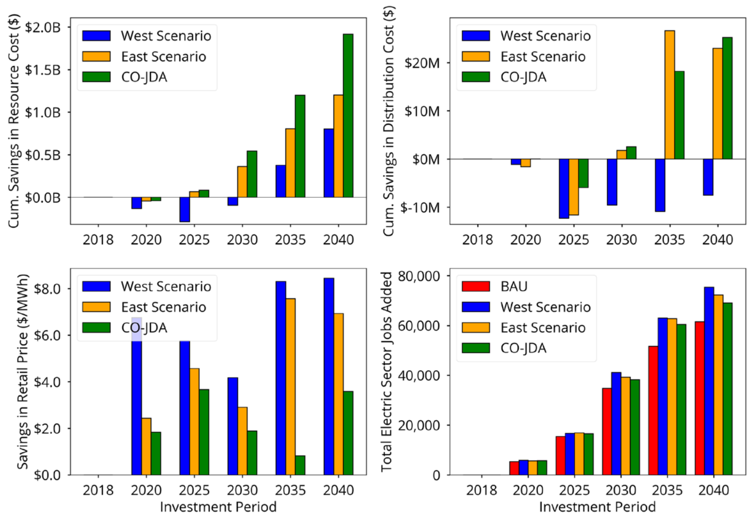


Figure 2.16: Differences in total resource costs (top left), distribution costs (top right), retail rates (bottom left) and jobs created (bottom right) for Colorado in the various scenarios compared to the BAU scenario.

With regards to jobs created, the "West" scenario produces the highest number of jobs in the electric sector at 75,375 full-time equivalents (FTE) by 2040. The other scenarios are close behind with the "East" scenario creating 72,242 FTEs by 2040 and the "CO-JDA" scenario creating 69,040 FTEs by 2040. The "BAU" scenario creates the lowest number of jobs at 61,528 FTEs by 2040.

The "West" scenario shows the largest savings in retail rates as under that scenario, Colorado increases it sales to Wyoming, Utah and New Mexico significantly. As seen from Fig. 2.17, in all scenarios, Colorado goes from being a net importer to a net exporter. However, the total exports see the largest increase in the "West" scenario reaching more than 4 TWh in 2040. The sale of excess energy into the large energy market afforded by the WEIM increases revenue for the utilities in Colorado and thus results in lower retail rates for customers.

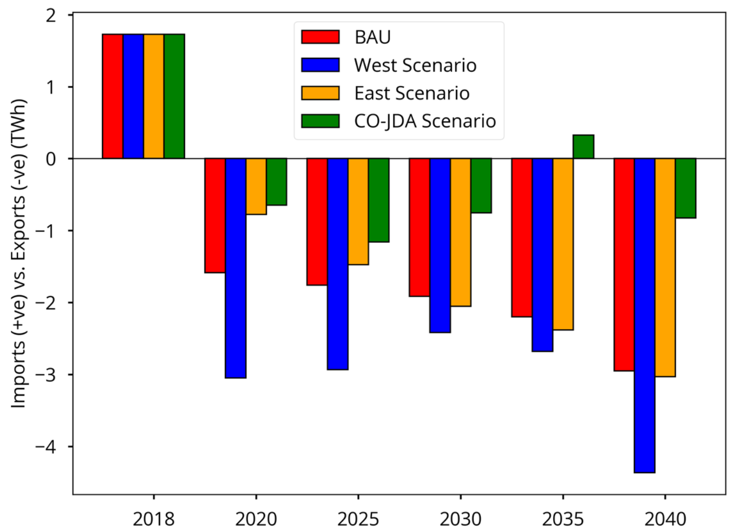


Figure 2.17: Net imports (positive) and exports (negative) from Colorado to its neighbors

Figure 2.18 shows the diurnal trend in imports and exports for Colorado for all scenarios in the year 2040. As seen from Fig. 2.18, the "West" scenario results in a significant increase in energy trading in terms of imports and exports. In this scenario, Colorado imports energy (on net) during the day to meet peak demand and take advantage of the cheaper solar generation abundant in the southwest region of WECC, while it exports excess wind generation in the evening through early morning hours.

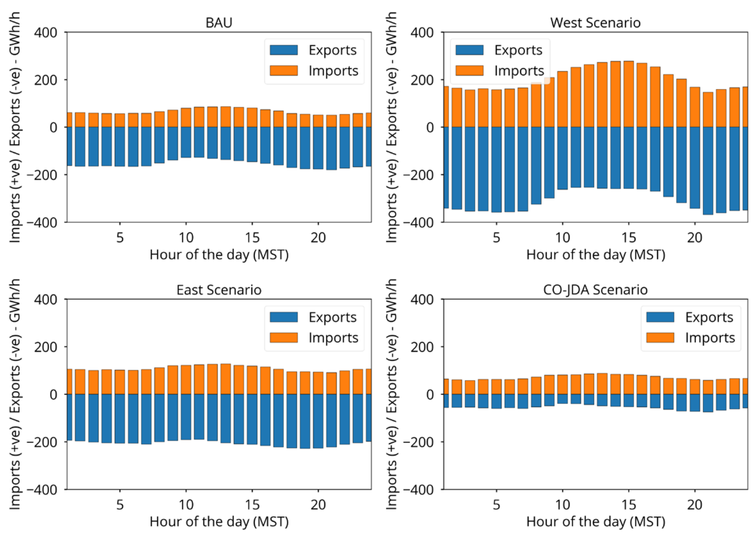


Figure 2.18: Diurnal trends in imports and exports for Colorado in the four scenarios in 2040.

In the "East" scenario, Colorado mainly exports energy to Oklahoma, but is limited in how much it can export due to the better wind resource available in the SPP region (see Section 3.5 for more details on weather analysis). In addition, the higher cost of transmission expansion (due to upgrade costs of DC ties) hinders growth of transmission and limits the participation of Colorado in the energy imbalance market.

2.6 Impact on Emissions

As seen from Section 2.4, the "BAU" scenario results in a 70% reduction in CO_2 emissions compared to 2018 levels. The "West" scenario produces the most additional emission savings with an additional 1% reduction in emission (from 2018 levels) which amounts to a cumulative saving of an additional 40 million metric tonnes of CO_2 (see Fig. 2.19). The "East" scenario produces the next highest reduction in emissions with an additional reduction of 20 million metric tonnes of CO_2 emissions. The reason for the slightly higher emissions compared to "West" scenario is due to about 314 MW of coal in Wyoming that does not retire by 2035, while the "West" scenario completely retires coal by 2035. The "CO-JDA" scenario is seen to have slightly higher cumulative CO_2 emissions compared to the "BAU" scenario by 2040 which is due to a combination of having slightly more gas generation and slightly less CCS generation resulting in higher CO_2 emissions.

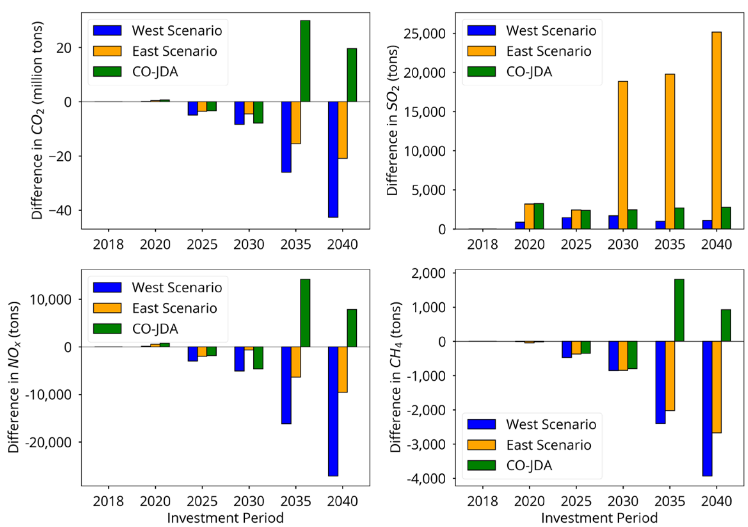


Figure 2.19: Cumulative changes in emissions over the WECC+SPP domain for the three scenarios compare to the "BAU" scenario.

In terms of SO_2 emissions, the "BAU" scenario almost completely eliminates SO_2 emissions from the electric sector. When compared to the "BAU" scenario, the "West" scenario is seen to have marginally higher cumulative SO_2 emissions due to the slightly higher generation from coal which is most probably within the bounds of model uncertainty. The SO_2 emissions for the "CO-JDA" are similarly marginally higher within bounds of model uncertainty. However, it is seen that in the "East" scenario, there is significantly higher SO_2 emissions compared to the "BAU" scenario. This is again due to the 314 MW of unretired coal in Wyoming. For the other species of pollutants, the trends are similar to those of CO_2 where the maximum reduction in emission is observed in the "West" scenario, followed by the "East" scenario and the "CO-JDA" scenario shows a slight increase in emissions compared to the "BAU" scenario.

The trends in change in emissions is observed to be completely different in Colorado compared the WECC+SPP domain as shown in Fig. 2.20. It is observed that in all species of pollutants except SO_2 the three scenarios result in lower emissions compared to the "BAU" scenario. In terms of CO_2, the lowest emissions are observed in "West" scenario with an additional reduction of 35 million tons of CO_2 by 2040 compared to the "BAU" scenario. The "CO-JDA" scenario is close behind with 32 million tons of CO_2 emission reductions by 2040. The "East" scenario results in an additional 25 million ton of CO_2 reductions by 2040 in compared to the "BAU" scenario.

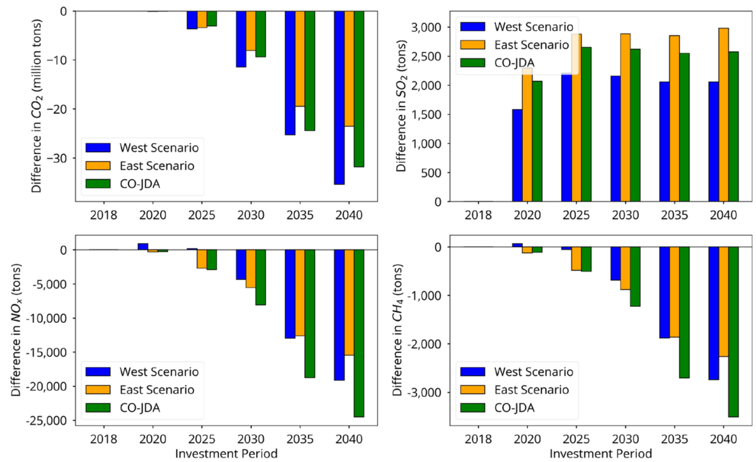


Figure 2.20: Cumulative changes in emissions in Colorado for the three scenarios compare to the "BAU" scenario.

In all three scenarios, SO_2 emissions are seen to be marginally higher compared to the "BAU" scenario. The SO_2 emissions in the three scenarios are about 3000 tons higher by 2040 compared to the "BAU" scenario. This marginally higher cumulative emissions are well within the bounds of model uncertainty given that SO_2 emissions were 281,000 tons per year in 2018 and are reduced to less than 2,000 tons per year by 2040.

The emission reductions compared to the "BAU" scenario come from lower utilization of gas generation to meet load in all scenarios compared to the "BAU" scenario (61.3% clean generation). As seen from Fig. 2.21, the "West" scenario has the highest generation from clean energy (68% clean) and lowest generation from natural gas and thus results in the lowest emission among all scenarios.

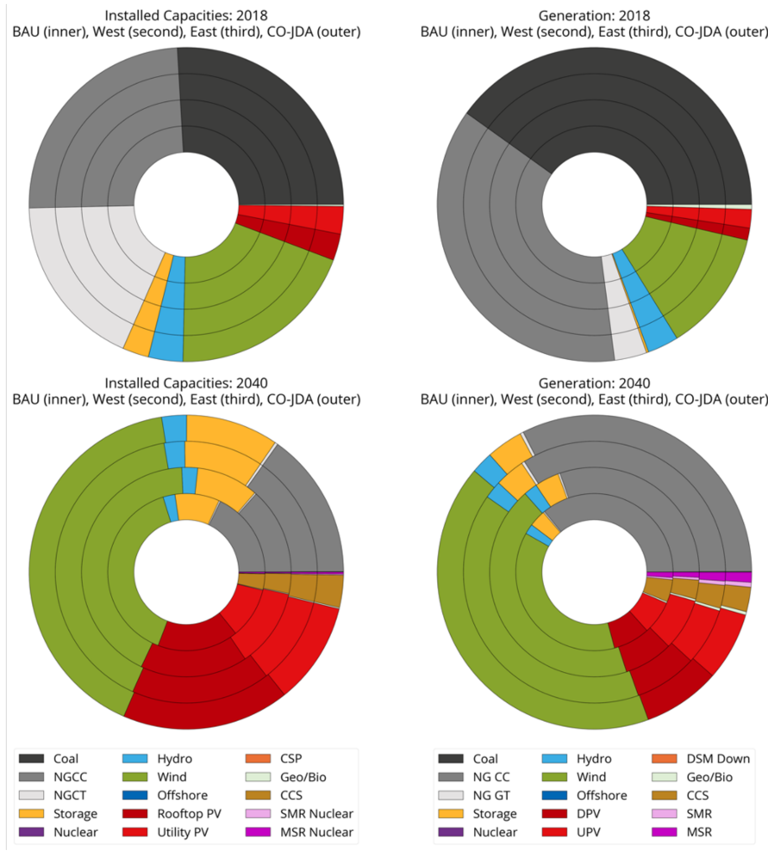


Figure 2.21: Installed capacities (left pie charts) and generation (right pie charts) in the scenarios modeled in 2018 (top) and 2040 (bottom)

The next lowest generation from gas is in the "CO-JDA" scenario (65.7% clean generation) which has the second lowest emissions among all scenarios. The "East" scenario has the lowest emission savings compared to the "BAU scenario (64% clean generation). This scenario uses the same amount of gas generation as the "BAU" scenario, but compensates through increased use of MSR and CCS and thus still able to reduce emissions compared to the "BAU".

2.7 Transmission Buildout

The four scenarios investigated in this study show interesting trends in not only the transmission buildout rates, but also where the transmission expansion occurs. WIS:dom® is allowed to build transmission in all four scenarios investigated. Figure 2.22 shows the inter-state transmission capacity from Colorado to its neighbors expands in all four scenarios. The "West" scenario is seen to have the largest increase in inter-state transmission capacity from Colorado to its neighbors among all scenarios. The reason for this is the significantly increased imports and exports with other members of the WEIM as explained in Section 2.5. Most of the new transmission built in the "West" scenario is to Wyoming, with smaller capacities added to New Mexico and Utah. The "East" and "CO-JDA" build less inter-state transmission compared to the "West" scenario and thus see lower economic benefits from sale of energy.

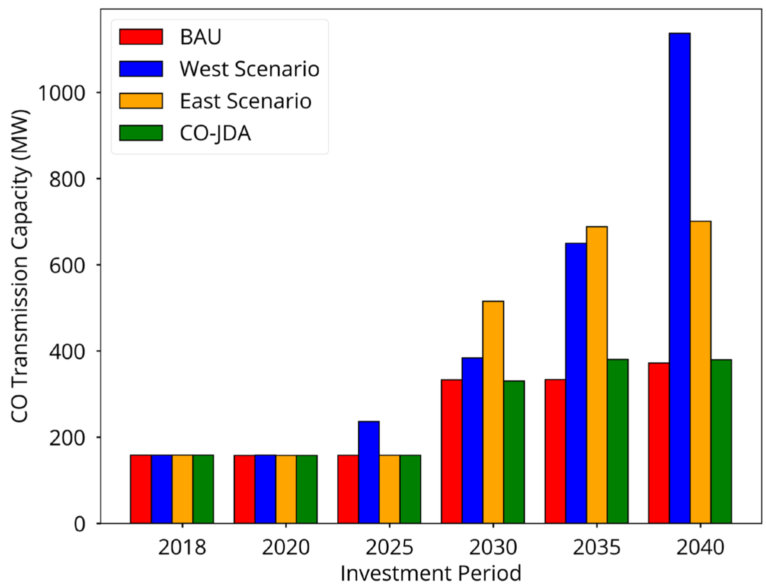


Figure 2.22 Transmission buildout from Colorado to neighboring states

The transmission buildout within Colorado also differs significantly between the various scenarios. Figure 2.23 shows the differences in transmission buildout in the various scenarios compared the "BAU" scenario. In the "West" scenario, it is observed that there is significant additional transmission being built to connect the northeastern part of Colorado to the load centers. These transmission buildouts extend from northeast part of Colorado to the load centers along the front range and continue on to central Colorado and connecting east to Kit-Carson county where there is another significant buildout of wind generation. Figure 2.24 shows a representation of the transmission lines built in the "West" scenario by 2040.

Most of the transmission buildout observed in the "West" scenario also develops in the "East" scenario, however there is significantly less transmission built between Wyoming and northeast Colorado. The "East" scenario sees a larger transmission buildout connecting southeast Colorado and Oklahoma to export and import wind generation between them.

All scenarios show that in-state transmission buildout is essential to bring VRE generation to the load centers.

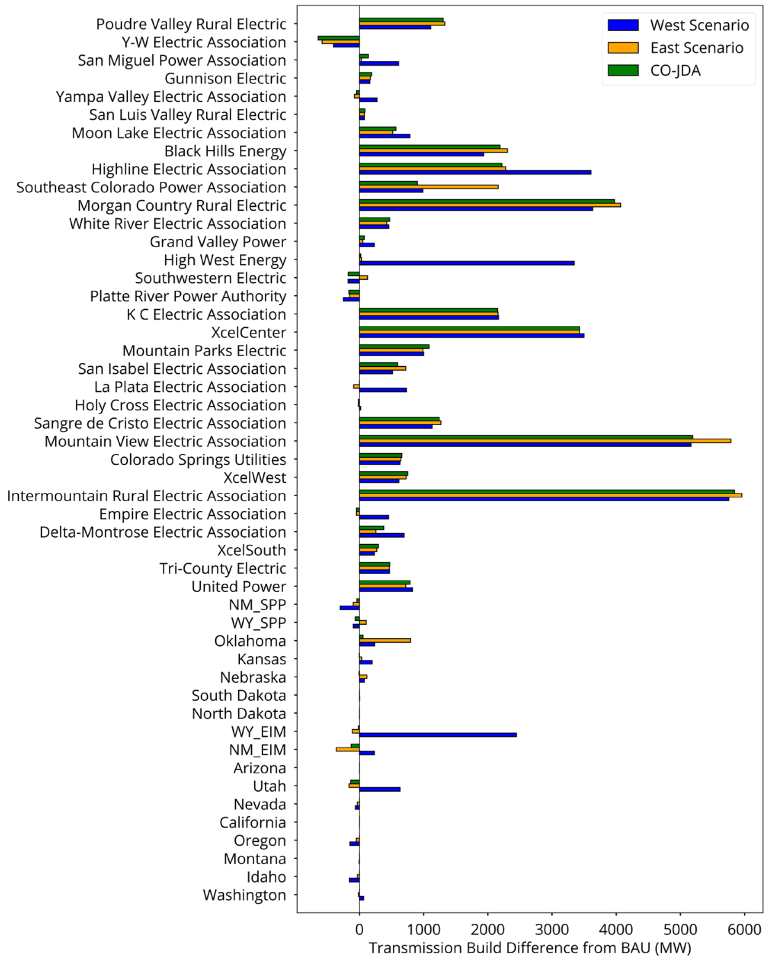


Figure 2.23: Difference in transmission capacity by 2040 compared to the "BAU" scenario.

Transmission buildout within Colorado in the "CO-JDA" scenario mirrors the "East" scenario however with a purpose to move energy within Colorado more efficiently. Therefore, there is very little increase in transmission capacity going out of Colorado and all transmission expansion is focused to connect the various utilities within Colorado. The reasons for these transmission buildout decisions are seen in changes to export and imports for Colorado shown in Fig. 2.18.

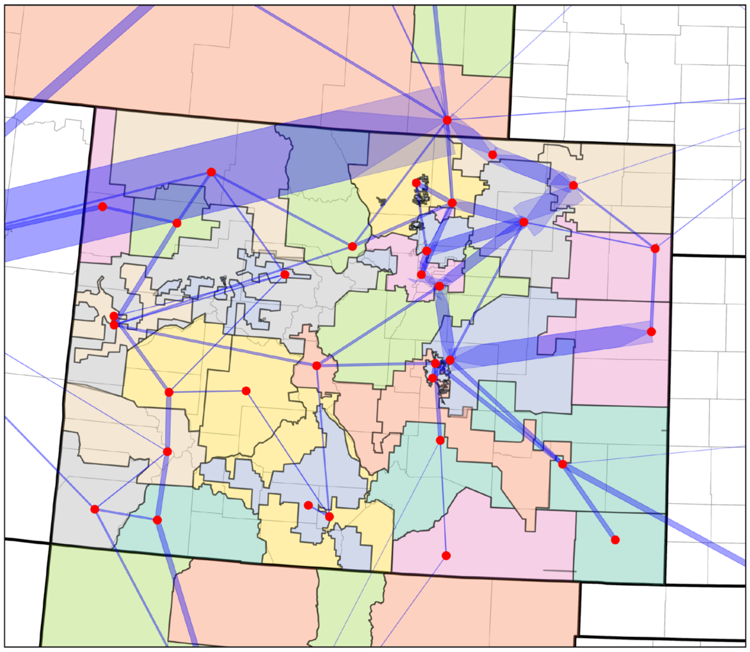


Figure 2.24: Representation of transmission capacities (proportional to width of blue arrows) built in the "West" scenario by 2040.

2.8 Siting of WIS:dom® installed generation

Using the multi-year 3-km, 5-min weather dataset available over the contiguous United States, WIS:dom® is able to perform optimal siting of generators. Figure 2.25 shows the existing generator capacities in 2018 on which the model is initialized and the WIS:dom® modeled generator siting in 2040. It is observed that there is significantly more wind and solar generation on the grid by 2040, coal is completely retired and California has the only nuclear generation in the WECC+SPP region.

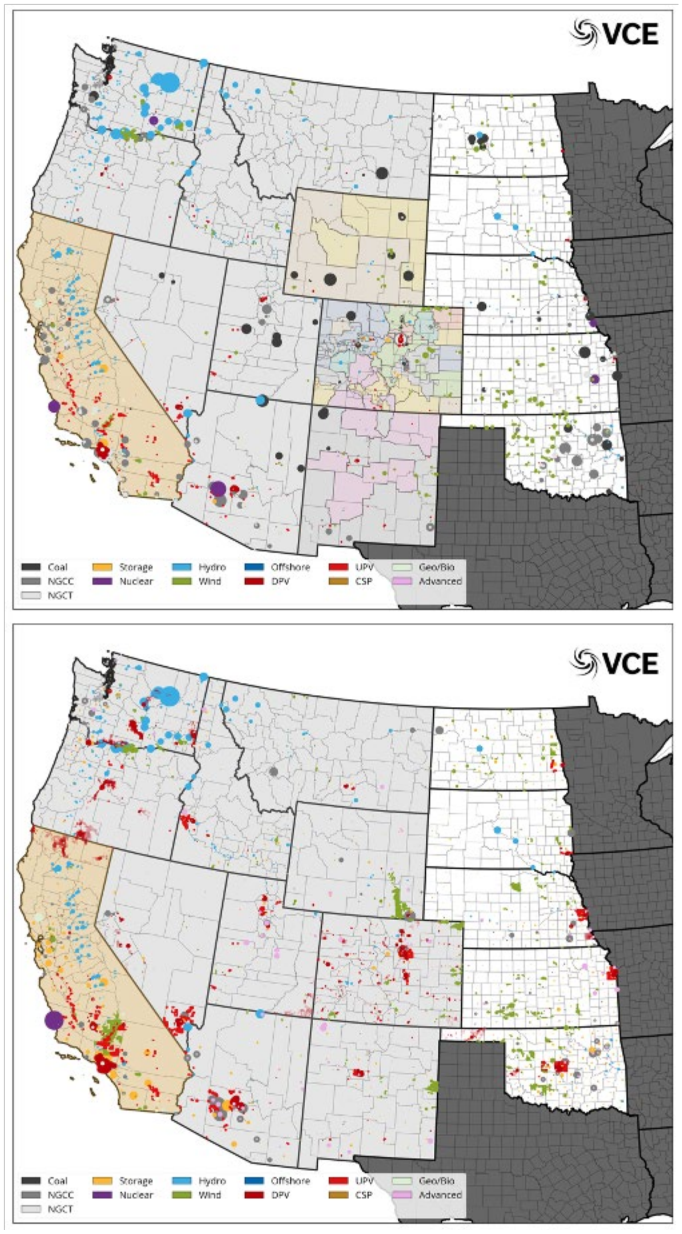


Figure 2.25: Existing generator siting in 2018 (top) and WIS:dom® modeled generator siting in 2040 (bottom) in the "West" scenario.

Within Colorado (see Fig. 2.26), it is observed that most of the new wind is installed in the northeast region of the state as well as in Kit Carson and Cheyenne counties. Most of the transmission buildout within Colorado focusses on connecting these regions of wind development with the load centers along the front range. Transmission is also built from the northeast region of Colorado to Wyoming to exchange the significant wind generation that gets installed around PacifiCorp's territory in Wyoming.

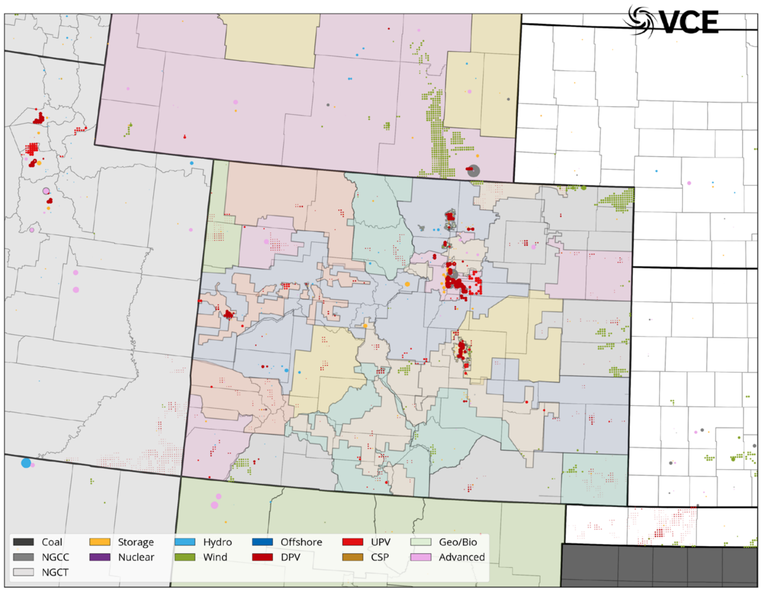


Figure 2.26: WIS:dom® installed generation by 2040 in the "West" scenario.

2.9 Reliability and Resource Adequacy

Grid reliability is an important aspect of energy system design. WIS:dom®-P ensures reliability by making sure that the installed capacities meet NERC criteria for planning reserve margins (PRM) for the model domain in addition to having 7% load following reserves at all times. Part of calculating resource adequacy is estimating the capacity value of variable energy sources such as wind, solar and storage. The capacity value of thermal generators is defined by the unforced capacity of these generators (given in Table 2.1) that takes into account each generator's forced outage rate.

Generator	Coal	NGCC	NGCT	Nuclear	Hydro	Geo	CCS	SMR	MSR
UCAP	87.7%	86%	85.3%	90.3%	89.5%	89.1%	86%	95%	95%

Table 2.1: Unforced capacity fractions for thermal generators

The challenge with estimating the capacity value of VREs is capturing the role they play in meeting load. Depending on the load shape, both seasonal and diurnal, the value of wind, solar and storage in meeting the load changes. In addition, with each installed unit of wind, solar and storage the value of the next installed unit changes based on the siting location unlike for thermal generation where it stays constant. For this reason, WIS:dom®-P incorporates capacity value endogenously into the optimal capacity expansion. As a result, WIS:dom®-P is constantly evaluating the impact of each siting decision on meeting load, reliability of the system and capacity value of that choice (to meet PRM constraints). Section 1.8 in the WIS:dom®-P technical documentation describes how this process in incorporated into the capacity expansion. In this section, the capacity value of the VRE generation mix chosen by WIS:dom®-P is evaluated using traditional methods of estimating capacity value.

One method to estimate the capacity value of VREs is through the Equivalent Load Carrying Capacity (ELCC) metric. The ELCC metric estimates the additional load a VRE can sustain with the same reliability as the original generation mix as a fraction of the VRE capacity. The average ELCC of wind, solar and storage in Colorado is shown in Fig. 2.27. Solar is seen to show a slight increase in ELCC from 46% in 2018 to 82% in 2020, before reducing gradually to 25% by 2040. The ELCC of wind is also seen to first increase from 17% in 2018 to 71% in 2025 before settling at 57% by 2040. The ELCC of wind increases from optimal siting of new wind resources that better match wind generation to load.

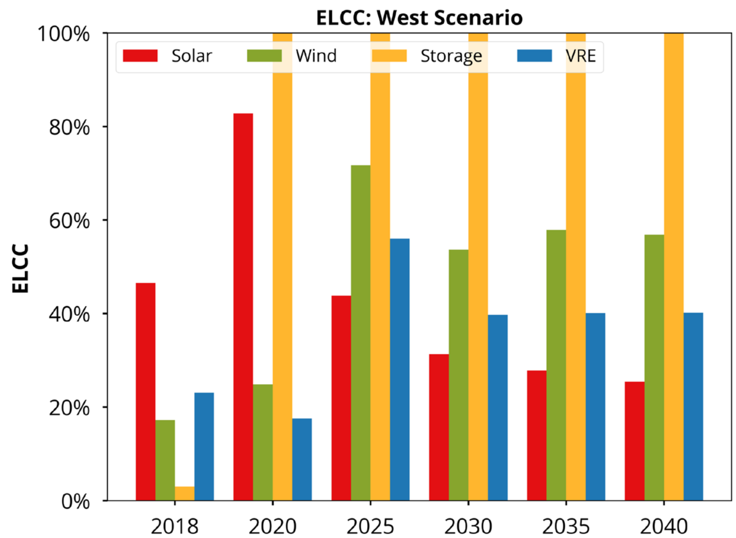


Figure 2.27: Average ELCC of wind, solar and storage in Colorado in the "West" scenario over the investment periods.

Storage is seen to have the most interesting characteristics in terms of its ELCC. In 2018, when only small amount of storage exists, its ELCC is low. However, as storage gets added over the investment periods, its ELCC is seen to increase to 100% and remain there until 2040. The reason for this change in ELCC can be understood by looking at how storage is being used by the model to meet load (see Fig. 2.28).

Figure 2.28 shows the diurnal average capacity factors for wind, solar and storage installed in Colorado for summer and winter periods in the "West" scenario in year 2040. It is seen that storage behavior remains largely the same irrespective of season. Storage is seen to work as a bridge during periods of transition from wind generation during the nighttime to solar generation in the day time. Since these periods are not always high stress events in terms of load, the ELCC value for storage is seen to remain high.

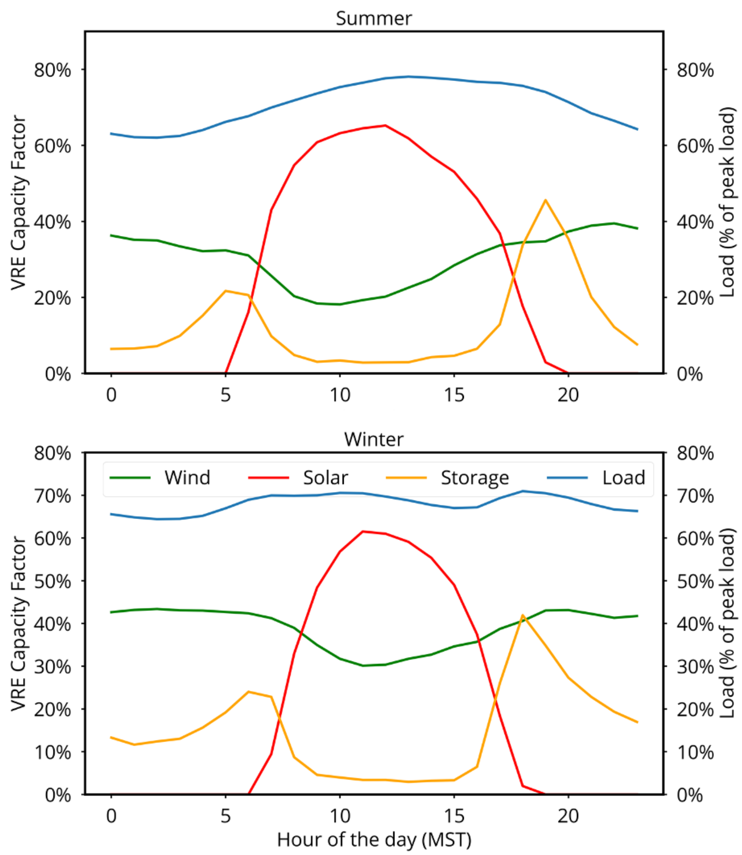


Figure 2.28: Diurnal trends in average capacity factors for wind, solar and storage in Colorado in summer (top) and winter (bottom) in the "West" scenario in 2040.

Another way to calculate capacity value is through estimating the role of VREs during periods of highest demand. The contribution of VREs during periods of peak demand can be estimated by calculating the reduction in load during hours of peak demand as a fraction of VRE installed capacity. The capacity value of wind, solar and storage estimated in this manner is shown in Fig. 2.29. While the trends in capacity value of wind and solar are different compared to the ELCC metric, the capacity value in 2040 are similar to the ELCC metric with solar at 20% and wind at 40%.

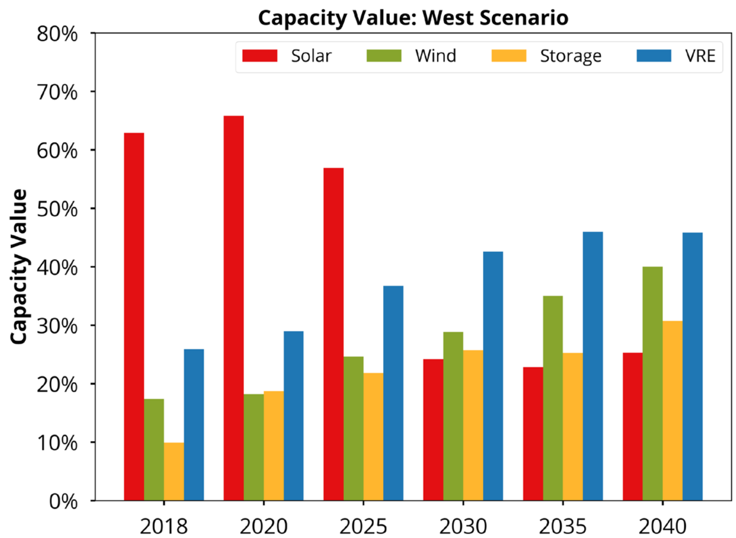


Figure 2.29: Capacity value of wind, solar and storage estimated based on contributions during periods of peak demand in the "West" scenario.

However, the capacity value of storage is seen to be much lower than the ELCC metric. The reason for this is again due to the role storage is seen to play in meeting load in Colorado. As shown in Fig. 2.28, storage comes into play during periods of transition from dominantly wind generation to solar generation which are not periods of peak demand in Colorado. Since the above metric measures contribution during periods of peak demand, storage gets a lower capacity value compared to wind and solar whose generation is correlated with load in winter and summer respectively.

Wind and solar show seasonal variability in generation and therefore the seasonal characteristics are expected to have an impact on their capacity value. Figure 2.30 shows the monthly averaged daily capacity value of wind, solar and storage over the year in the "West" scenario in year 2040. The trends in capacity value of wind and solar follow expected trends based on trends in seasonal generation characteristics.

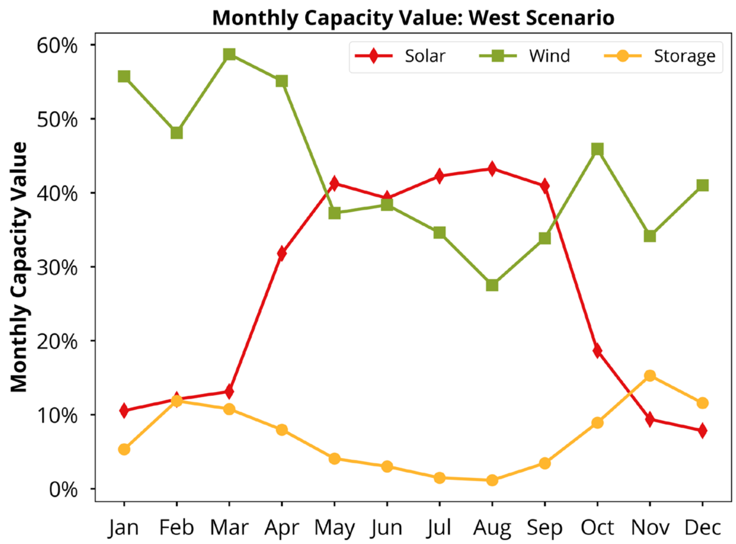


Figure 2.30: Seasonal variation in capacity value to wind, solar and storage in 2040 in the "West" scenario.

As seen from Fig. 2.30, wind has higher capacity factors in the winter periods, while solar has higher capacity values in spring, summer and fall. Storage is seen to have low capacity values throughout the year with higher values in the winter periods.

3. VCE® Datasets & WIS:dom®-P Inputs

3.1 Generator Input Dataset

VCE® processed the Energy Information Administration annual data from 2018 to create the baseline input generator dataset for this study. From this dataset, information for the various footprints investigated in this study (CAISO + EIM, SPP, Colorado and WECC) was obtained. The western US has a very large geographic extent. These regions, CAISO + EIM, SPP, Colorado and WECC, contain approximately 132, 87, 18 and 235 GW of generation capacity respectively. WIS:dom® has the ability to solve over such scales at 5-minute resolution for several years chronologically.

The generator input datasets are based off the publicly available EIA 860 and EIA 923 data. 2018 data is used for this study. We go through several steps to align and aggregate technology types to the 3-km grid space to match with the National Oceanic and Atmospheric Administration (NOAA) High Resolution Rapid Refresh (HRRR) model weather data. In the process, we also analyze year-on-year changes. Across the US, general trends show coal capacities falling with natural gas combined cycle growing. Wind, solar and storage plants are on the rise as well. This continues into the released December EIA 860M 2019 Monthly data.

The following outlines the process VCE® undergoes to prepare the generator input datasets:

1. *Data is merged between the EIA 860 and EIA 923 data.*
2. *Initial quality control is applied to the data.*
3. *The location of the generators is assigned to the nearest 3 km HRRR cell. This can be more difficult for generators on state boundaries as well as land/water boundaries. As such, extra time is given to ensure that the mapped generators are correct.*
4. *The generator types in each 3 km grid cell is aggregated . As an example, if two separate coal plants are in the same grid cell, the capacity is summed for coal in that grid cell.*
5. *Further spatial checks are performed to make sure the output aligns with the original data.*
6. *Final model input format is produced. A county level average of all generator types is also created.*

VCE® also works with the Catalyst Cooperative (https://catalyst.coop/), a company with the goal of helping the energy research community by processing major publicly available sources into a format that is organized and stream-lined to use. This helps our processes become quicker and eventually more frequent on this input dataset.

1	Coal
2	Natural Gas Combined Cycle
3	Natural Gas Combustion Turbine
4	Storage
5	Nuclear
6	Hydroelectric
7	Onshore Wind
8	Offshore Wind
9	Residential Solar
10	Utility-scale Solar
11	Concentrated Solar Power
12	Geothermal
13	Biomass
14	Other Natural Gas
15	Other Generation
16	Natural Gas - CCS
17	Pumped Hydro Storage
18	Small Modular Reactors
19	Molten Salts

Figure 3.1: The VCE® generator technology bins.

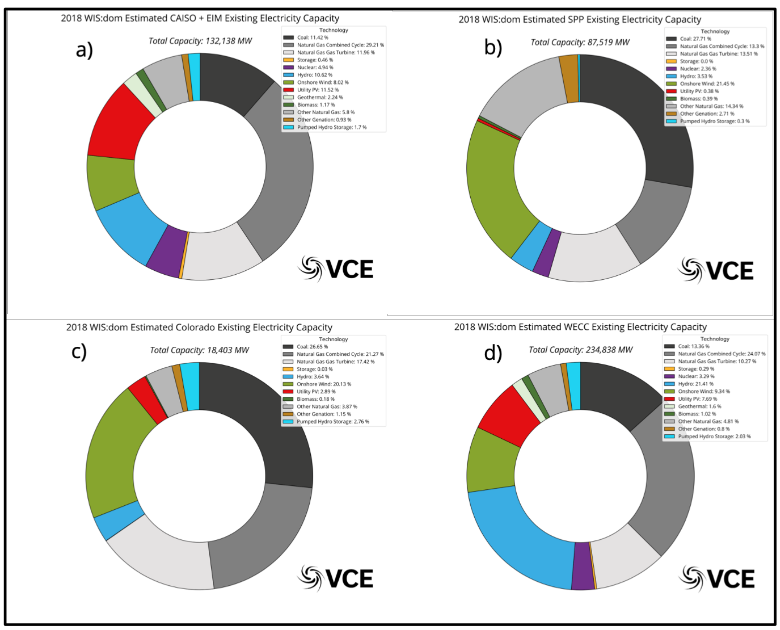


Figure 3.2: WIS:dom® estimated installed capacity for a) CAISO + current EIM participants, b) SPP, c) the state of Colorado and d) WECC. The total capacity modeled for each region is 132, 87, 18 and 235 GW respectively.

Figure 3.2 shows the installed capacities for generator technologies over various footprints across the western US. Starting with WECC, it is notable that over a third of installed capacity is renewable. Hydro is the largest presence amongst renewables. CAISO and EIM installations look very similar to WECC which shows how much of WECC is influenced by this subset region. CAISO and EIM have a good mix of renewables. Solar brings in the largest percentage of installed capacity among the renewables installed. CAISO and EIM also have two large nuclear plants within its footprint (one in California and another in Arizona). CAISO itself has about 20 GW less installed capacity than SPP ISO. However, including the EIM, SPP is much smaller in terms of installed capacity. It is instantly observed how much of SPP's fleet is wind capacity. The remainder of the fleet is predominantly thermal. Colorado also has an almost equal percentage of wind installed when comparing to SPP ISO. There is no nuclear installed in Colorado. Almost 75% of Colorado's installed generator capacity is currently non-renewable units. For further comparison, below, this same information is shown for the entire contiguous US installed fleet in Figure 3.3.

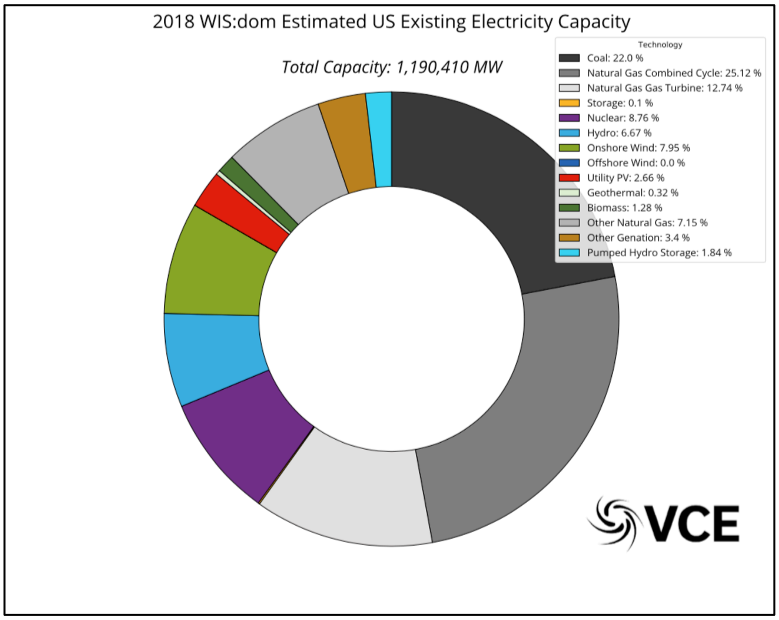


Figure 3.3: WIS:dom® estimated capacity share for the contiguous United States. The total capacity modeled is 1,190,410 MW.

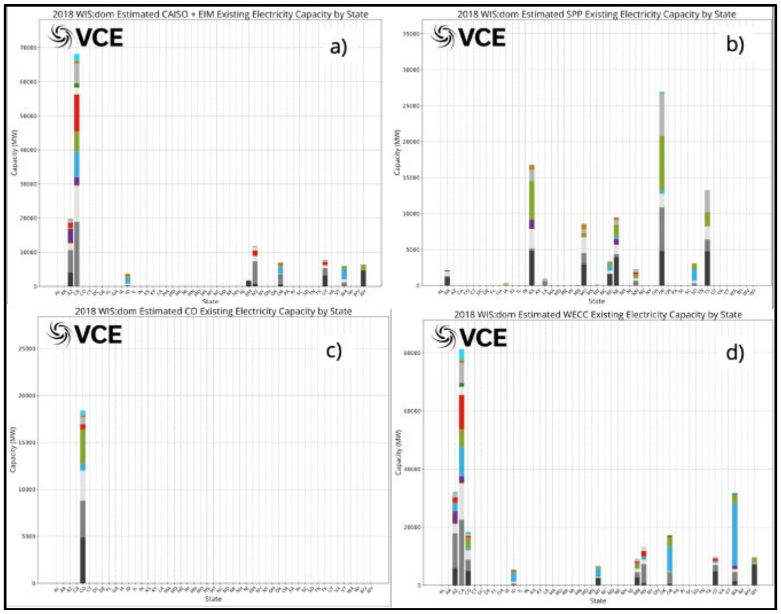


Figure 3.4: WIS:dom® Capacity installed broken out by state for a) CAISO + current EIM participants, b) SPP, c) the state of Colorado and d) WECC.

Figure 3.4 shows the stacked installed technology capacity by state within each region of interest and Figure 3.5 shows the spatial locations of installed generators across the various regions in the western US modeled for this study. These images combined reveal the following: California has the largest amount of capacity installed across all the western states. Solar is incredibly prominent in southern California. This state has only a single coal plant near Searless Valley. On the flip side, coal is the most dominant technology in Wyoming. Both California and Arizona have utility scale storage showing up as a smaller slice of their total installations. Across the west, the majority of hydro exists in the Rocky Mountain ranges, the Sierra Nevada mountain range and the Cascades. Colorado has wind installed all along the eastern portions of the state. It also has solar installed in larger clusters along the front range and in the San Luis valley. The two largest coal plants in Colorado are the Craig (northeast Colorado) and Comanche (outside Pueblo) plants. In SPP, the state of Oklahoma holds the largest percentage of installed generation in that region. The coal installations are highest across Kansas, Oklahoma and the Texas portion of this ISO. Oklahoma, followed by Kansas, holds the most amount of wind installations.

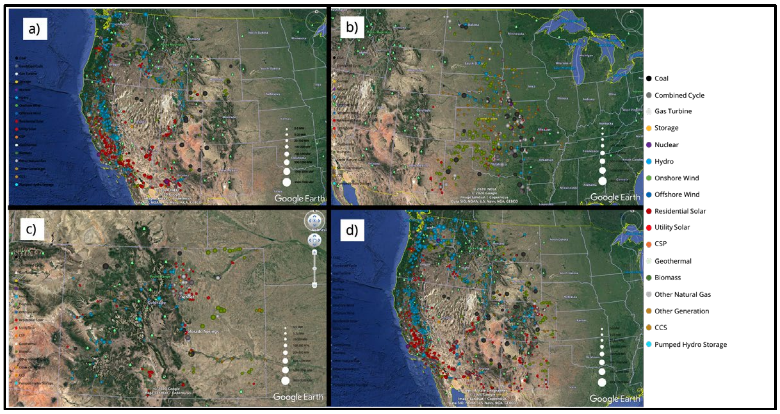


Figure 3.5: WIS:dom® estimated location of various technologies for a) CAISO + current EIM participants, b) SPP, c) the state of Colorado and d) WECC.

3.2 Creating Colorado Utility Dataset

For this study, VCE investigated and analyzed all the electric power companies in Colorado, including utilities, cooperatives, generation and transmission companies as well as various city municipalities. To simplify the modeling, if a municipality was small enough, VCE would absorb this company into its larger geographic surrounding entity. For instance, the town of Oak Creek is surrounded by the Yampa Valley Electric Association. Most of the power supply for Yampa Valley Electric comes from Xcel Energy. Hence, the municipality of Oak Creek will get modeled as a part of Xcel Energy. This was performed based on the size of the load the entity served and where the majority of its power supply came from. Due to the load sizes represented along the metropolitan Front Range of Colorado, many power entities in that area were kept separate. As an example, Longmont Electric and Colorado Springs Utilities remain individual utilities that are modeled by WIS:dom®. All told there were 58 power companies considered and reviewed across Colorado. These were simplified down to 32 regions within the state that were resolved by the model, the two largest entities being Xcel and Tri-State. This can be observed in the following table (Table 3.1).

The input generator dataset within Colorado was investigated in great detail to determine which Colorado electric company owns each asset. A simple case is the Rush Creek Wind Farm owned and operated by Xcel Energy. That is made sure to be attributed to Xcel's fleet of generators. Further, for units not owned by utilities, it was determined who was the main power purchaser of a given plant or unit. As an example, in this case, many wind farms along the eastern plains have PPAs with Xcel Energy, even though those wind farms fall within Tri-State cooperative territory. This analysis ensured a higher fidelity data fit of the current usage of the various resources across Colorado and that assets were represented in the appropriate entities within the WIS:dom®. To note, Xcel Energy was broken out into Xcel South (San Luis Valley), Xcel Central (Front Range) and Xcel West (Grand Junction area) given the separated geographic areas of the company.

In Wyoming and New Mexico, VCE® performed a closer look at the power companies in these states as well. Many entities here already provide power to either CAISO EIM or SPP. VCE® determined to the best our ability which power entities belonged in either the west or east power markets. This allowed, once again, for a more complete picture of the current setup of the western power layout for the WIS:dom® model to start with.

Utility/Cooperative	Surrounding Parent Utility/Cooperative	Simplified/Surrounding Parent Entity
Aspen Municipal	Holy Cross Electric Association	Holy Cross Electric Association
Black Hills Energy	Black Hills Energy	Black Hills Energy
Burlington Municipal	K C Electric Association	Tri-State
Center Municipal	San Luis Valley Rural Electric	Tri-State
Colorado Springs Utilities	Colorado Springs Utilities	Colorado Springs Utilities
Delta Municipal	Delta-Montrose Electric Association	Tri-State
Delta-Montrose Electric Association	Delta-Montrose Electric Association	Tri-State
Empire Electric Association	Empire Electric Association	Tri-State
Estes Park Light and Power	Mountain Parks Electric	Tri-State
Fleming Electric	Highline Electric Association	Tri-State
Fort Collins Utilites	Fort Collins Utilites	Fort Collins Utilites
Fort Morgan Utiltiies	Morgan Country Rural Electric	Tri-State
Fountain Electric	Colorado Springs Utilities	Colorado Springs Utilities
Frederick Municipal	United Power	Tri-State
Glenwood Springs Electric	Holy Cross Electric Association	Holy Cross Electric Association
Granada Electric	Southeast Colorado Power Association	Tri-State
Grand Valley Power	Grand Valley Power	Xcel
Gunnison Electric	Gunnison Electric	Tri-State
Gunnison Light and Power	Gunnison Electric	Tri-State
Haxtun Light and Power	Highline Electric Association	Tri-State
High West Energy	High West Energy	Tri-State
Highline Electric Association	Highline Electric Association	Tri-State
Holly Municipal	Southeast Colorado Power Association	Tri-State
Holy Cross Electric Association	Holy Cross Electric Association	Holy Cross Electric Association
Holyyoke Municipal	Highline Electric Association	Tri-State
Intermountain Rural Electric Association	Intermountain Rural Electric Association	Xcel
Julesburg Municipal	Highline Electric Association	Tri-State
K C Electric Association	K C Electric Association	Tri-State
La Junta Municipal	Black Hills Energy	Black Hills Energy
La Plata Electric Association	La Plata Electric Association	Tri-State
Lamar Utiliies	Southeast Colorado Power Association	Tri-State
Las Animas Municipal	Southeast Colorado Power Association	Tri-State
Longmont Electric	Longmont Electric	Longmont Electric
Loveland Water and Power	Fort Collins Utilites	Fort Collins Utilites
Lyons Municipal	Poudre Valley Rural Electric	Tri-State
Moon Lake Electric Association	Moon Lake Electric Association	Moon Lake Electric Association
Morgan Country Rural Electric	Morgan Country Rural Electric	Tri-State
Mountain Parks Electric	Mountain Parks Electric	Tri-State
Mountain View Electric Association	Mountain View Electric Association	Tri-State
Oak Creek Electric	Yampa Valley Electric Association	Xcel
Poudre Valley Rural Electric	Poudre Valley Rural Electric	Tri-State
San Isabel Electric Association	San Isabel Electric Association	Tri-State
San Luis Valley Rural Electric	San Luis Valley Rural Electric	Tri-State
San Miguel Power Association	San Miguel Power Association	Tri-State
Sangre de Cristo Electric Association	Sangre de Cristo Electric Association	Tri-State
Southeast Colorado Power Association	Southeast Colorado Power Association	Tri-State
Southwestern Electric	Southwestern Electric	Tri-State
Springfield Municipal	Southeast Colorado Power Association	Tri-State
Tri-County Electric	Tri-County Electric	Xcel
Trinidad Municipal	San Isabel Electric Association	Tri-State
United Power	United Power	Tri-State
Wheatland Electric	Southeast Colorado Power Association	Tri-State
White River Electric Association	White River Electric Association	Tri-State
Wray Light and Power	Y-W Electric Association	Tri-State
Xcel Energy	Xcel Energy	Xcel
Y-W Electric Association	Y-W Electric Association	Tri-State
Yampa Valley Electric Association	Yampa Valley Electric Association	Xcel
Yuma Municipal	Y-W Electric Association	Tri-State

Table 3.1: All Colorado electric power companies simplified to a limited amount of entities modeled by WIS:dom®.

3.3 Renewable Siting Potential Dataset

VCE® performs an extensive screening procedure to determine the siting potential of new generators across the contiguous US. This ensures that the WIS:dom® model has constraints on where it can build new generation. First, USGS land cover information is utilized as a base within each 3 km grid cell to determine what is there (Figure 3.6 top left panel). Figure 3.7a shows this same information at a closer look of the western states. Figure 3.7b shows a zoomed in looked at Colorado itself for reference.

The first screening algorithm follows these steps:

1. *Remove all sites that are not on appropriate land-use categories.*
2. *Remove all sites that have protected species.*
3. *Remove all protected lands; such as national parks, forests, etc.*
4. *Compute the slope, direction and soil type to determine its applicability to VRE installations.*
5. *Determine the land cost multipliers based on ownership type.*
6. *Remove military and other government regions that are prohibited.*
7. *Avoid radar zones and shipping lanes.*
8. *Avoid migration pathways of birds and other species.*

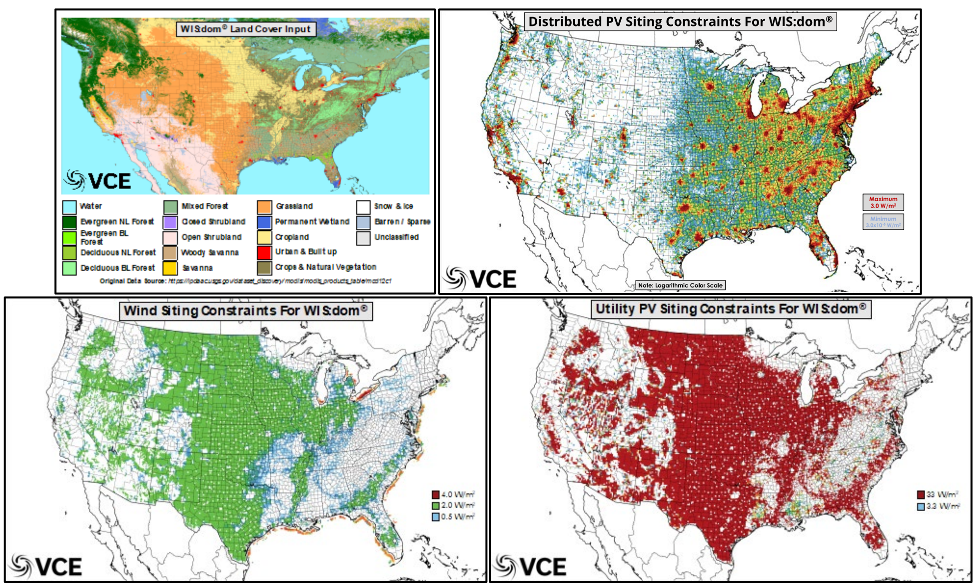


Figure 3.6: WIS:dom® land cover (top left), distributed solar PV siting bounds (top right), utility-scale wind bounds (bottom right) and utility-scale solar PV (bottom right).

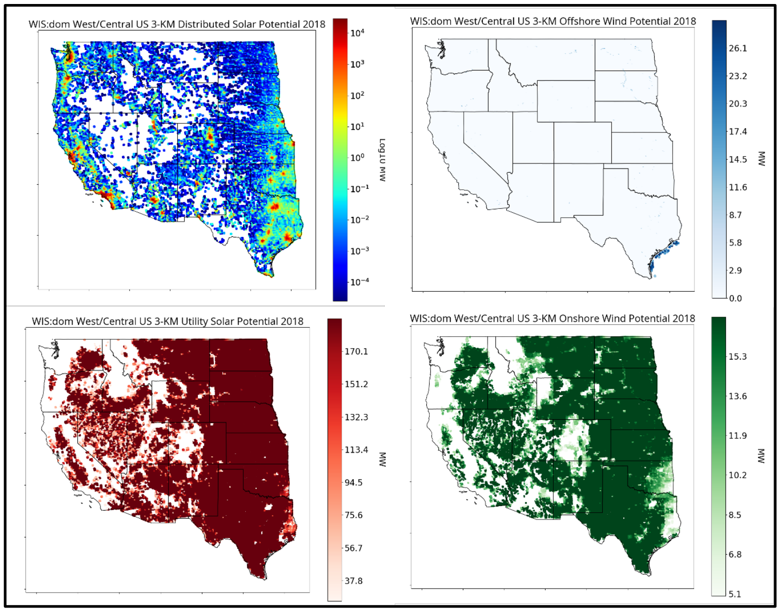


Figure 3.7a: WIS:dom® Rooftop Potential (top left), Offshore Wind Potential (top right), Utility-scale Solar Potential (bottom right) and Onshore Wind Potential (bottom right) in MW. The Distributed Solar Potential is converted to a Logarithmic Base 10 scale due to the ranges of value for that parameter. This is a closer look at the Western states.

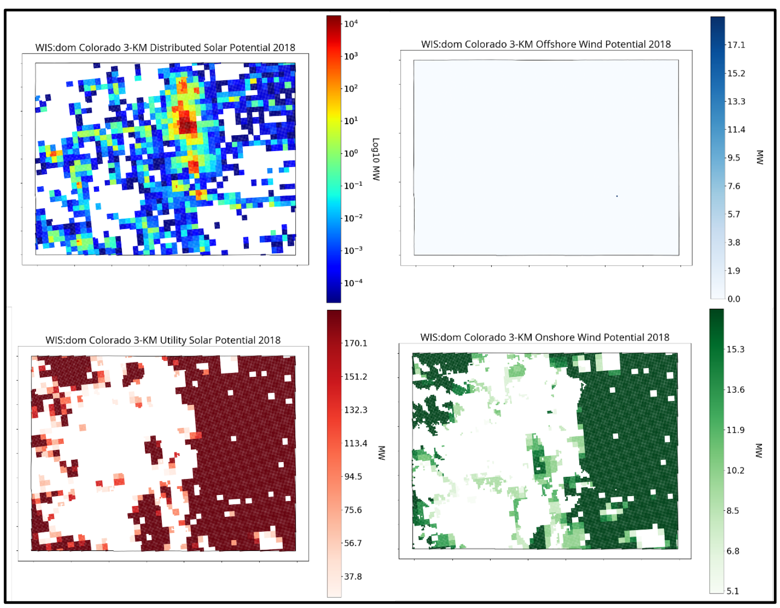


Figure 3.7b: WIS:dom® Rooftop Potential (top left), Offshore Wind Potential (top right), Utility-scale Solar Potential (bottom right) and Onshore Wind Potential (bottom right) in MW. The Distributed Solar Potential is converted to a Logarithmic Base 10 scale due to the ranges of value for that parameter. This is a closer look at just Colorado.

The above, along with the knowledge of what is already built within a HRRR cell from the Generator Input data provides WIS:dom® with a view of where it can technically build certain generators as well as certain technologies. Figure 3.6 shows the siting constraints for wind, utility-scale solar PV and distributed solar PV.

For wind, utility-scale solar PV, distributed solar PV, and battery storage the available space is converted into capacity (MW & MWh) by assuming a density for each technology. This is particularly important for wind and solar PV because of wake effects and shading effects, respectively. The maximum density of wind turbines within a model grid cell was restricted to no more than one per km^2 (< 4 MW / km^2). Solar PV was restricted to a maximum installed capacity of 33 MW per km^2. For storage, it is assumed for a 4-hour battery the density is 250 MW / km^2. For all thermal generation, the density assumed for new build is 500 MW / km^2. Thus, for a 3-km grid cell the resulting maximum capacities (in the CONUS) are:

- Wind – 36 MW;
- Utility Solar PV – 297 MW;
- Distributed solar PV – 68 MW;
- Storage (4-hr) – 2,250 MW or 9,000 MWh;
- Thermal generators – 4,500 MW.

These densities and values also ensure that WIS:dom® does not over build in a single grid cell because the combined space is constrained, as these numbers are maximums assuming only that technology exists.

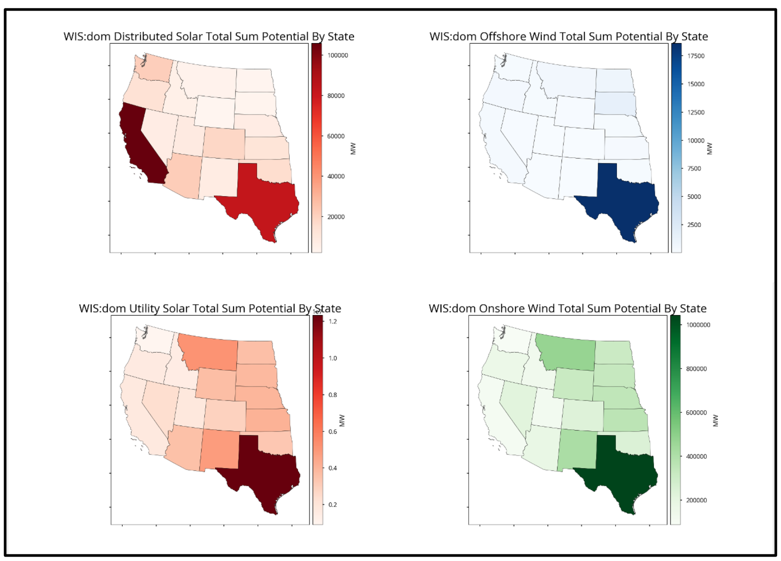


Figure 3.8: WIS:dom® Total Sum Potential by state for Rooftop (top left), Offshore Wind (top right), Utility-scale Solar (bottom right) and Onshore Wind (bottom right) in MW for the Western and Central states.

Figure 3.8 shows that California has the highest potential for distributed solar with Texas following in second. In general, the more populous states provide more buildings for rooftop solar. Offshore wind has the highest potential in Texas in the shallow Gulf waters. Utility solar potential is highest in Texas. The central states generally have more potential for utility solar as well with Montana and New Mexico coming in next to Texas. This pattern is also similar with onshore wind.

3.4 Standard Inputs

There is a standard suite of input data for the WIS:dom®-P model that sets the stage for several base assumptions about the energy grid and generator technologies. This includes:

- Generator cost data (capital, fixed, variable, fuel);
- Generator lifetime terms;
- Standard generator heat rates;
- Transmission/Substation costs;
- Legislation in the energy sector:
    - Renewable portfolio standards;
    - Clean energy mandates;
    - GHG emissions requirements;
    - Storage and offshore mandates;
    - PTC/ITC;
- Jobs for various technologies.

This is a list of the most commonly discussed standard inputs the model uses and are looked at in this document. The above list is not exclusive and much more information is ingested by WIS:dom®-P to narrow down characteristics of various generation technologies. The list of standard files is constantly growing as the industry evolves. Additional inputs can be easily incorporated into WIS:dom®-P.

The standard inputs remain constant throughout the scenarios modeled for the study unless specifically requested to change. However, the standard inputs are changing within each scenario throughout each investment period modeled. The overnight capital, fixed O&M and variable O&M costs for each generator technology are predominantly based upon the NREL ATB values unless otherwise noted. The NREL values were chosen as reputable and widely accepted values; are used by RTOs in their modeling and give high granularity and are updated frequently. The fuel costs come from the EIA Annual Energy Outlook data, another source that is reputable and regularly updated. VCE® provides fuel and capital costs multipliers by state to further tune the locational variation of these standard cost inputs. Other standard inputs are a combination of VCE® internal research and work with various partners in the industry.

These input assumptions are ingested into WIS:dom®-P to provide insight and bounds to the optimization selections for each investment period. It offers the model a picture of what cost options are available to optimize.

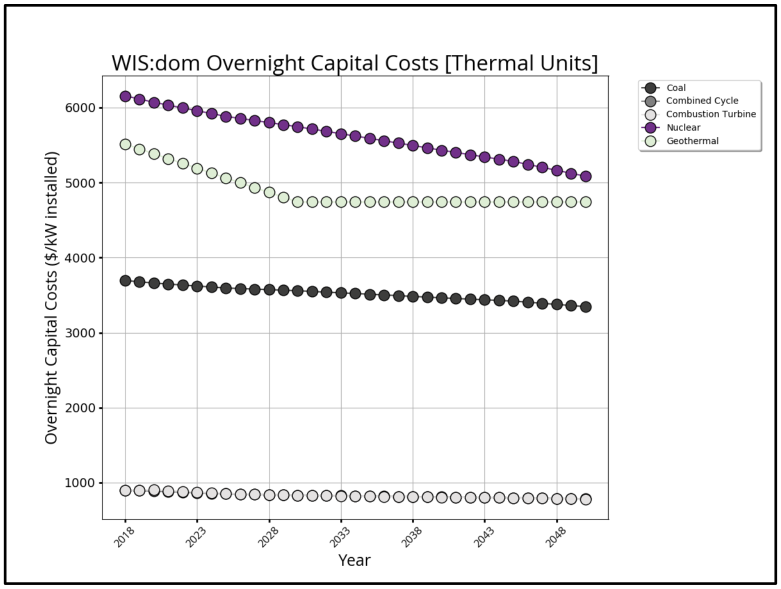


Figure 3.9: The overnight capital costs in real $/kW-installed for thermal power plants in WIS:dom®-P.

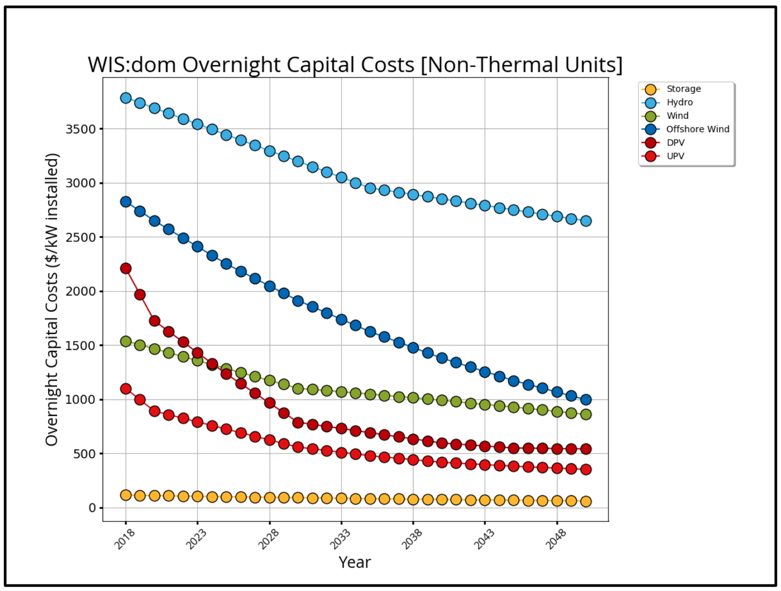


Figure 3.10: The overnight capital costs in real $/kW-installed for non-thermal power plants in WIS:dom®-P. All costs are from NREL ATB 2019, with the exception of storage costs, which were provided by Able Grid, Inc.

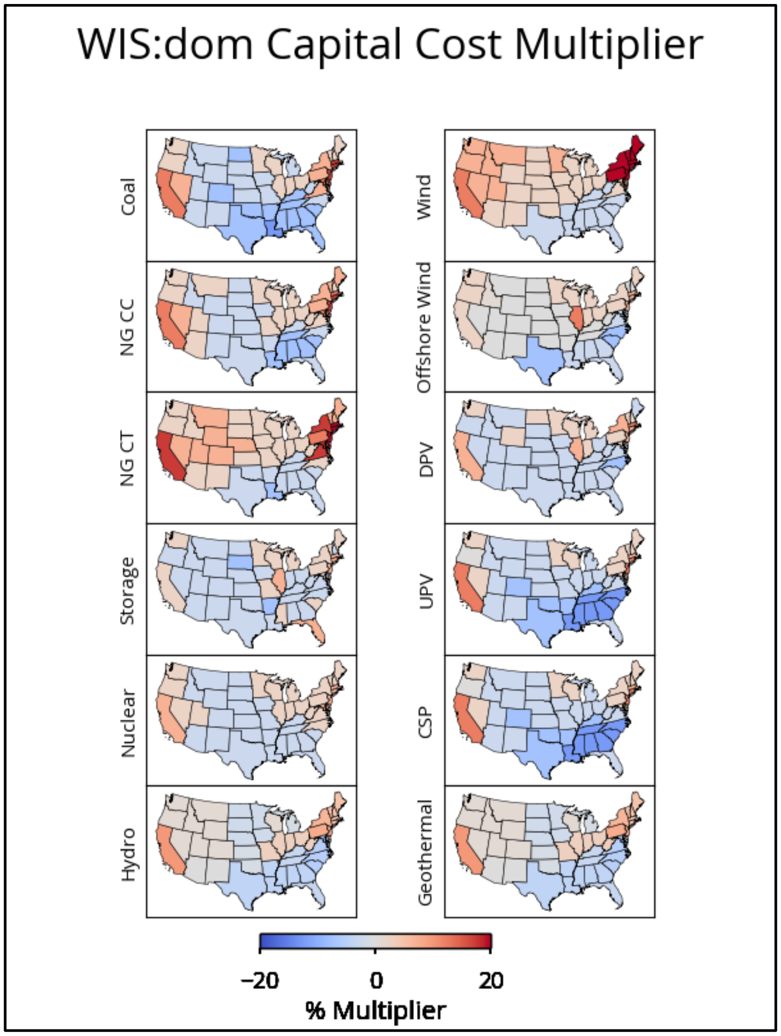


Figure 3.11: The WIS:dom® -P Capital Cost Multiplier is shown by state for each technology across the US. Shades of red show where the capital cost is scaled higher by a given percentage. Cool shades show where technology capital costs in the model are scaled down by a given percentage.

The previous figure shows that certain states and regions actually experience lower capital costs when building many technologies from the NREL ATB values. It is shown that Texas and, in general, the southeast United States, have lower capital costs for all generator technologies. Storage capital cost is the one exception in the southeast that is more expensive, though not for all southeast states. Certain technologies like Wind and Natural Gas Combustion Turbine technologies are more expensive in the Intermountain West. Wind is especially expensive in the northeast. In general, California and the New England states consistently show higher capital costs multipliers for all generator technologies.

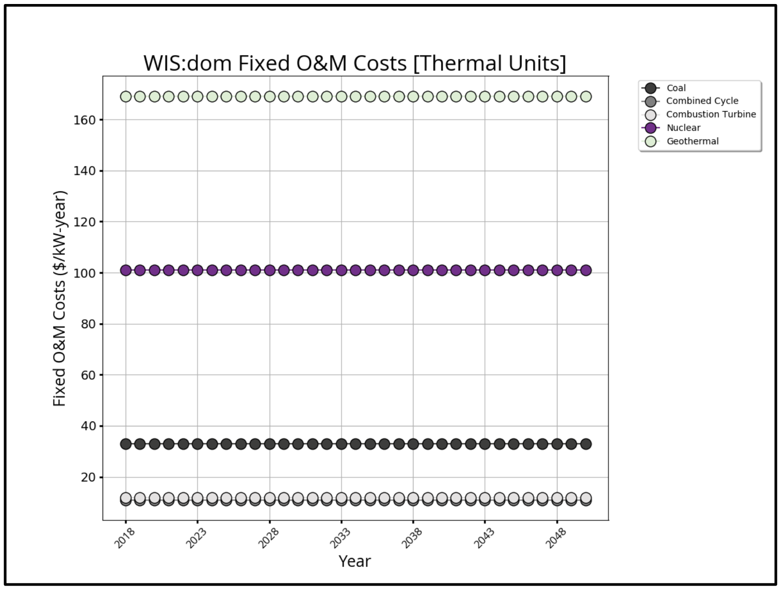


Figure 3.12: The fixed operations and maintenance (O&M) costs in real $/kW-yr for thermal power plants in WIS:dom®-P.

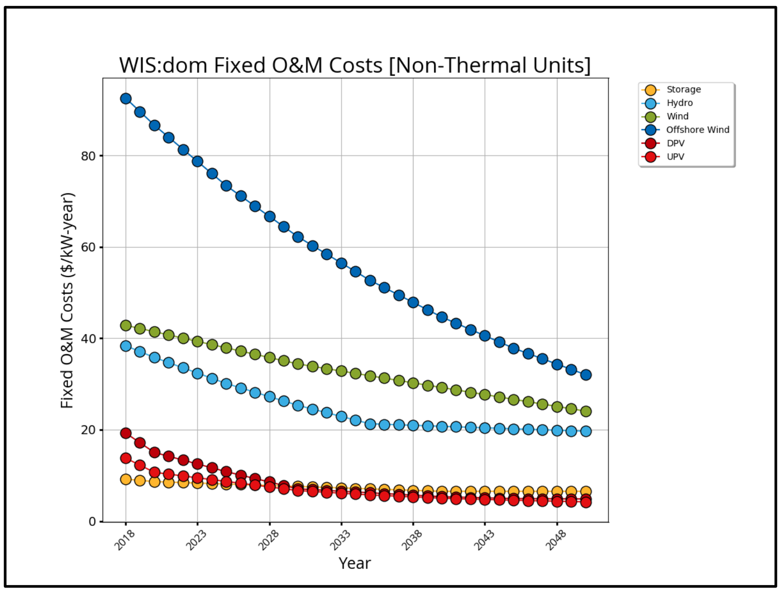


Figure 3.13: The fixed operations and maintenance (O&M) costs in real $/kW-yr for non-thermal power plants in WIS:dom®-P.

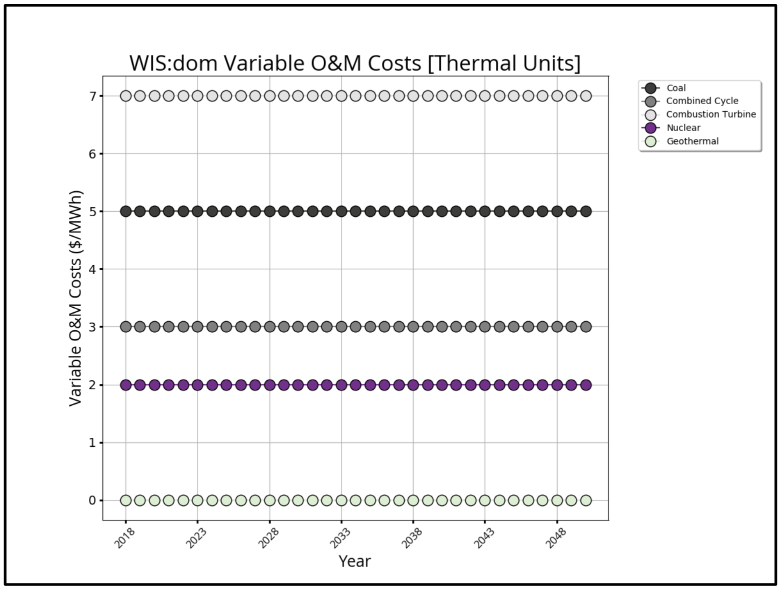


Figure 3.14: The non-fuel variable O&M costs for thermal generators in WIS:dom®-P in real $/MWh. The non-thermal units have zero variable O&M costs as those costs are combined into the fixed O&M costs.

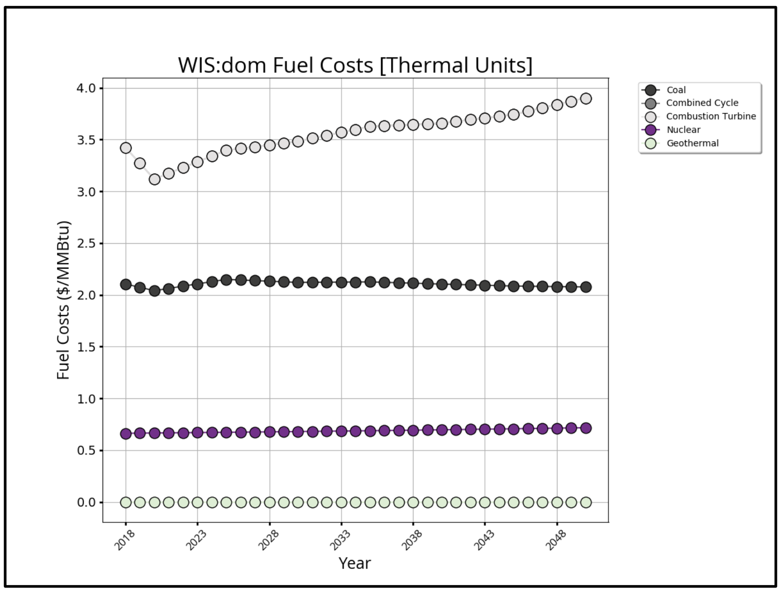


Figure 3.15: The fuel costs for thermal generators in WIS:dom®-P in real $/MMBtu.

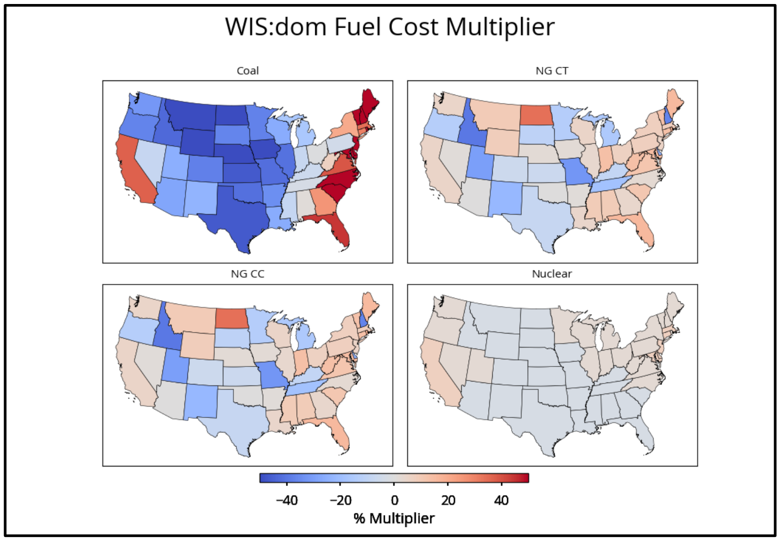


Figure 3.16: The WIS:dom®-P Fuel Cost Multiplier is shown by state for each technology across the US. The color scale shows a percentage multiplier applied to standard fuel costs. Shades of red show where the fuel cost is scaled higher by a given percentage. Cool shades show where technology fuel costs in the model are scaled down a given percentage. Renewable fuels are not shown here as those fuel costs are the same no matter where the technology is and those fuel costs are null.

The previous figure shows the spatial variations of fuel costs for thermal units (except geothermal since that cost is zero). California and the New England states show higher fuel costs for most of the technologies. New Hampshire is an exception for natural gas. Fuel costs for coal are much lower in the middle portion of the country. Natural Gas fuel costs are notably lower in Idaho, Utah, New Mexico, Missouri and New Hampshire. There is no fuel cost multiplier applied to renewable fuels (wind, solar, hydro) as those are the same everywhere across the US and they are fuels that have no cost.

Storage is one of the most discussed inputs. Storage can have highly variable cost input values depending on sources. It also is a heavy driver as to how the model handles renewables, transmission and future baseload. The following figure shows the difference between the 2019 NREL Low ATB costs for storage versus sources from Able Grid, Inc. VCE uses the latter in the modeling for storage.

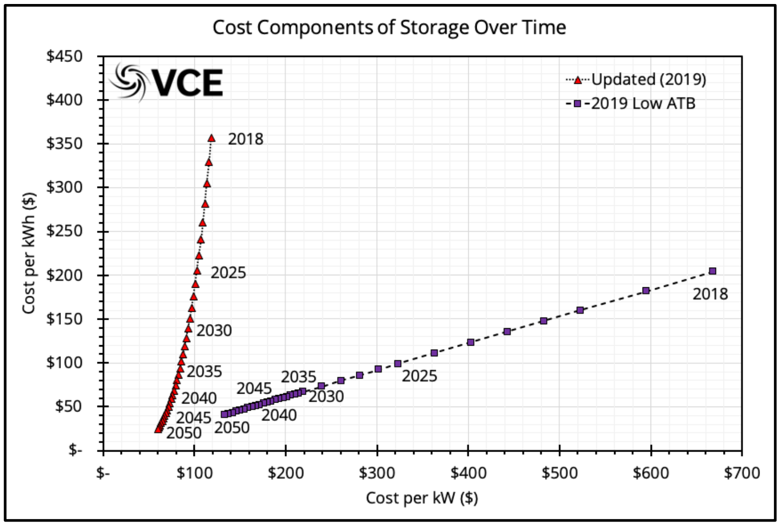


Figure 3.17: The Balance of System Capital Cost ($/kw) versus the Battery Pack Capital Cost ($/kWh). This is shown for the 2019 Low NREL ATB values in purple. The same information from Able Grid, Inc is show in red. The latter is used in the WIS:dom®-P model.

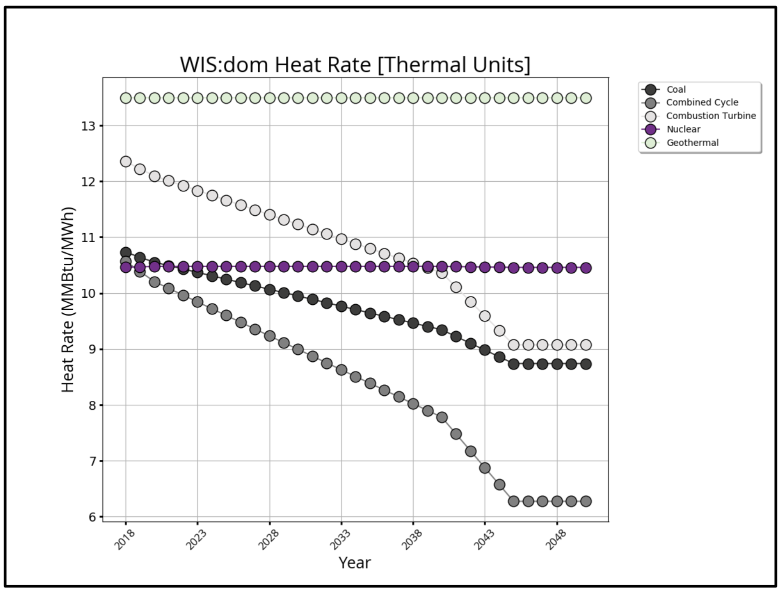


Figure 3.18: The generic heat rate for thermal generators in WIS:dom®-P in MMBtu/MWh of electricity generated. Explicit heat rates for currently installed generators come into the model through the Input Generator Datasets and the EIA 860/923 data.

We use the same discount rate for all generator technologies in the WIS:dom®-P model. This value is 0.0587 (%) which rolls into the cost equations within the model. The lifetime of the various technologies also impacts what/when the model optimally deploys generation as well as when it can retire units. The following figures shows the standard economic lifetimes for the various technologies used within WIS:dom®-P.

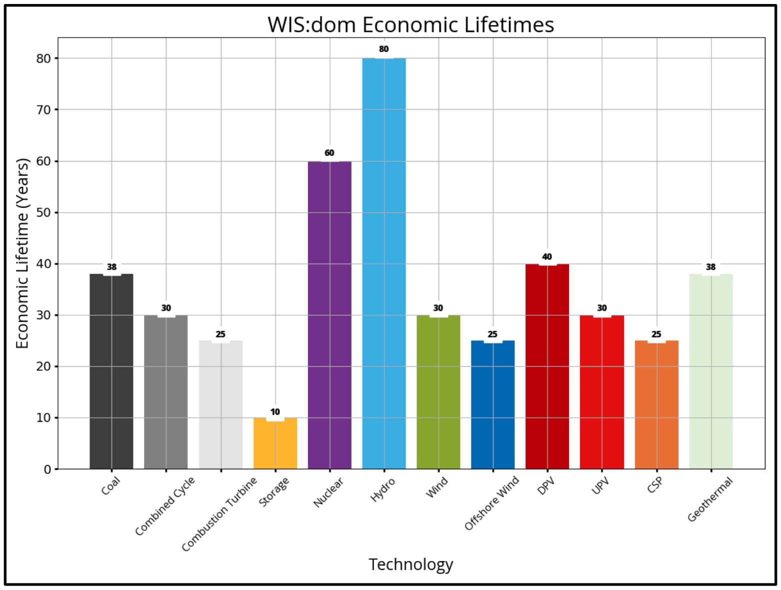


Figure 3.19: The economic lifetime for each generator type within WIS:dom®-P in years. The economic lifetime means the time that the debt must be cleared from the units.

Transmission plays a large part in the optimization decisions that the WIS:dom®-P model executes. The decision to build renewable technologies can be affected by transmission buildout costs and capacity of transmission buildout allowed.

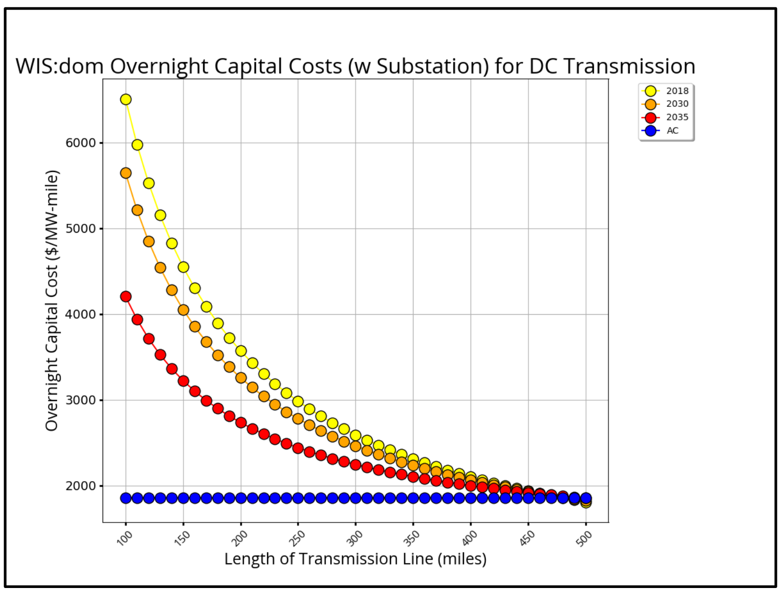


Figure 3.20: Shows the overnight capital cost of DC transmission in WIS:dom®-P in real $/MW-mile installed over various distances. Costs are shown for 2018, 2030 and 2050. The overnight capital cost of AC transmission (including substations) is also shown in blue. This is the same cost no matter the investment period.

The economic lifetime, or rather, length of amortization, of the transmission assets in the model are 60 years for all investment periods.

VCE® documents and researches the various state legislature and renewable energy goals by tracking Renewable Portfolio Standards, Clean Energy Mandates, Offshore Wind

Mandates, Storage Mandates and GHG Emission Reduction Mandates. These are utilized to inform the WIS:dom®-P model of expectations and goals. This provides the bounds and definitions of what the model is required to build as it optimizes systems of the future. Over 30 states have a renewable portfolio standard in place. Just over 10 states currently have a clean energy mandate. The northeast has become increasingly aggressive in setting offshore wind energy targets. Storage mandates have started to show up in recent years as well. The following figures lay out the current legislative for 2050. The Production Tax Credit and the Investment Tax Credit for renewables assumed to expire or decline as currently enacted, which directly impacts the cost of renewables built in WIS:dom®-P.

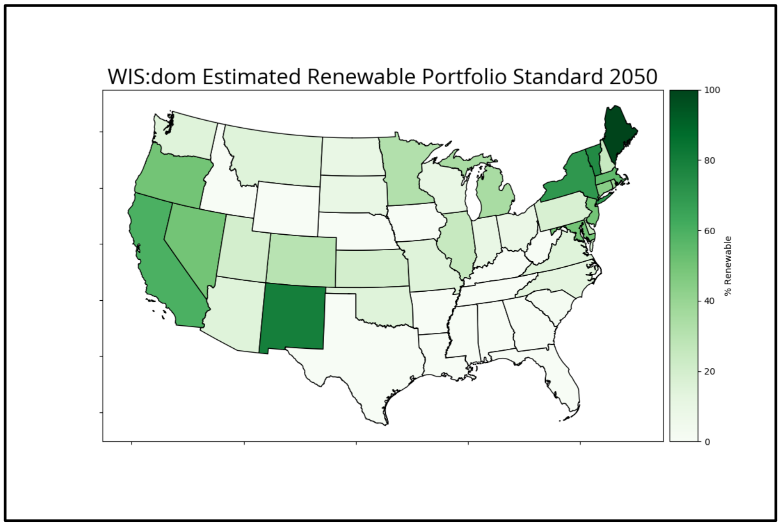


Figure 3.21: The Renewable Portfolio Standards percentage requirement of each state across the US.

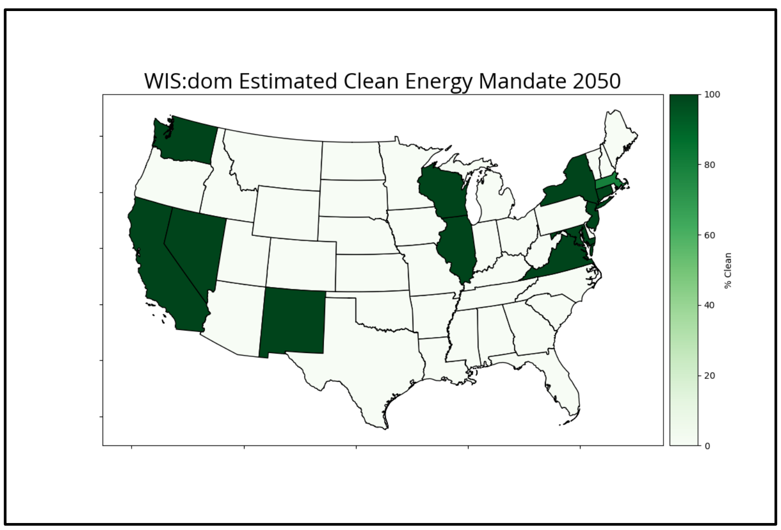


Figure 3.22: The Clean Energy Mandate percentage requirements of each state across the US.

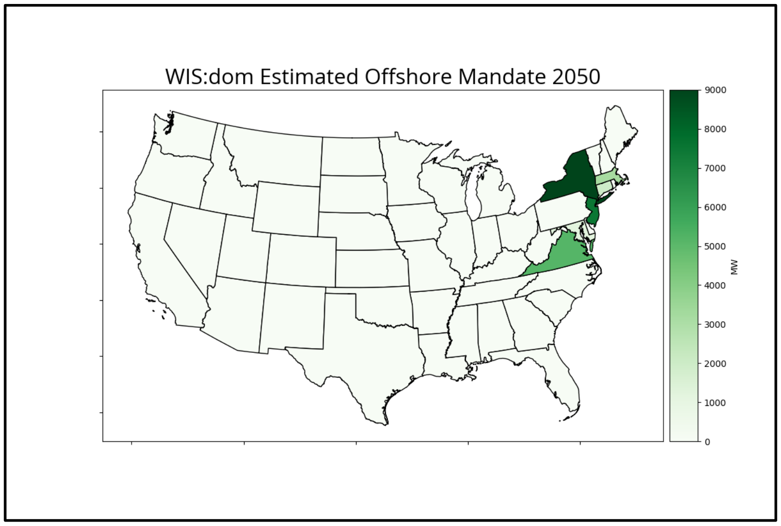


Figure 3.23: The Offshore Wind requirement in MW for each state across the US.

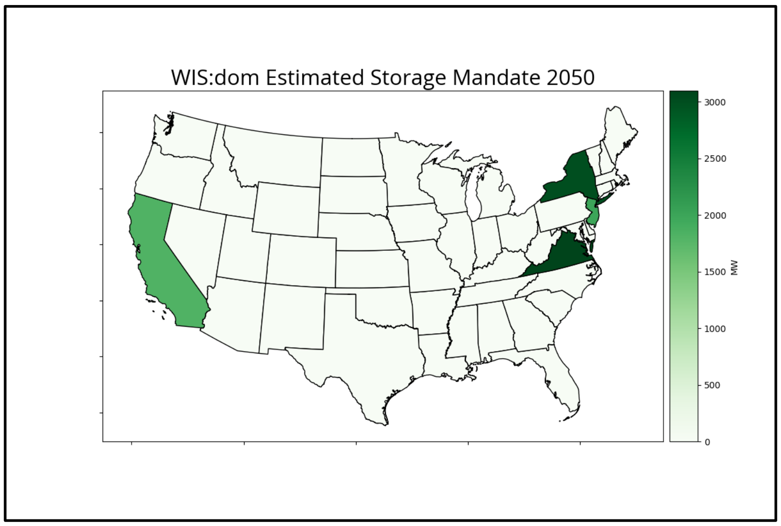


Figure 3.24: The Storage Mandates requirement in MW for each state across the US.

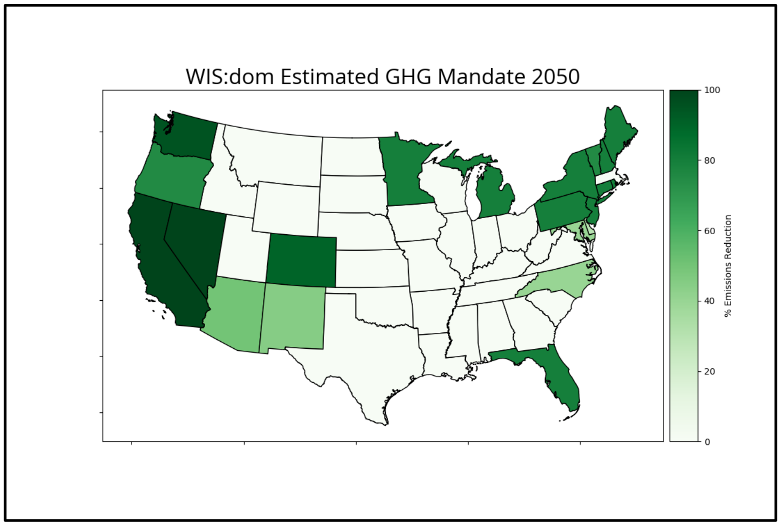


Figure 3.25: The GHG Emissions Reduction percentage requirement of each state across the US.

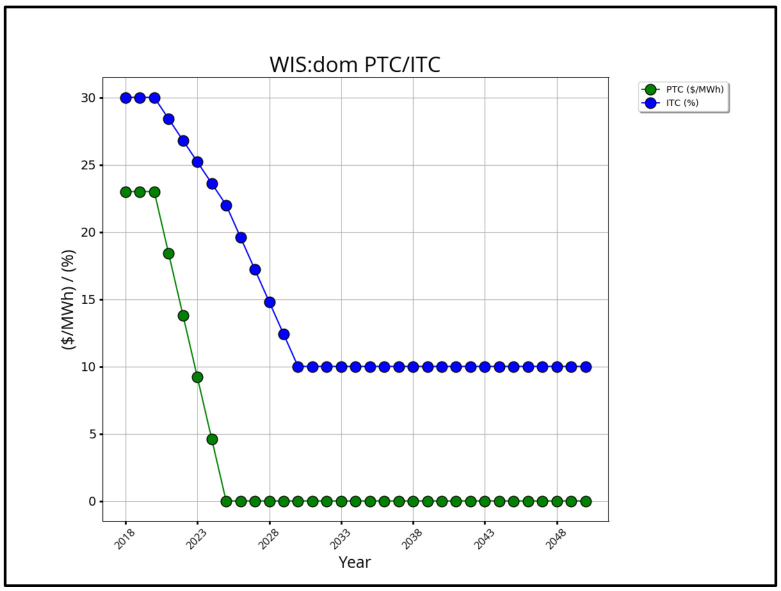


Figure 3.26: The Production Tax Credit subsidiary and the Investment Tax Credit. Note that for 2030 and beyond, the 10% ITC remaining is for utility scale projects only.

VCE® also performs work and analysis to represent job numbers that arise from various technologies and transmission across the US. These inputs set the stage for how many jobs become available depending on what is deployed during the various investment periods. This is an important metric for decision makers to know and understand as the energy industry evolves. VCE® uses a combination of sources to derive these numbers including IMPLAN, JEDI and US Energy Job reports.

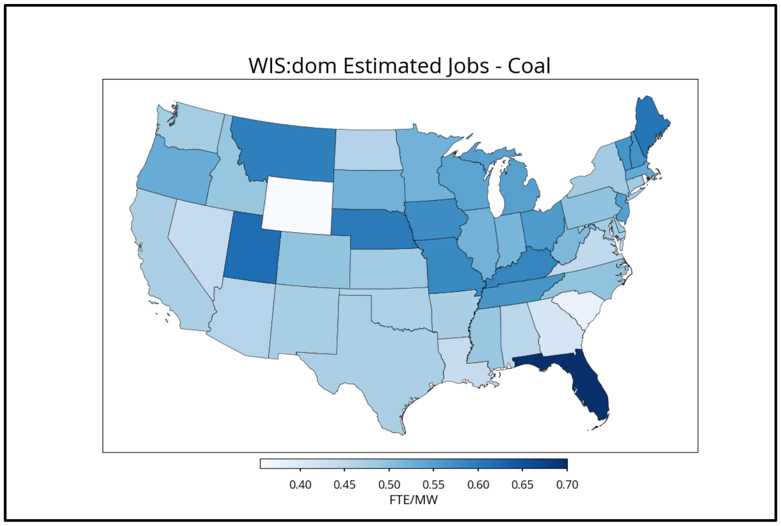


Figure 3.27: Employment per MW available from Coal.

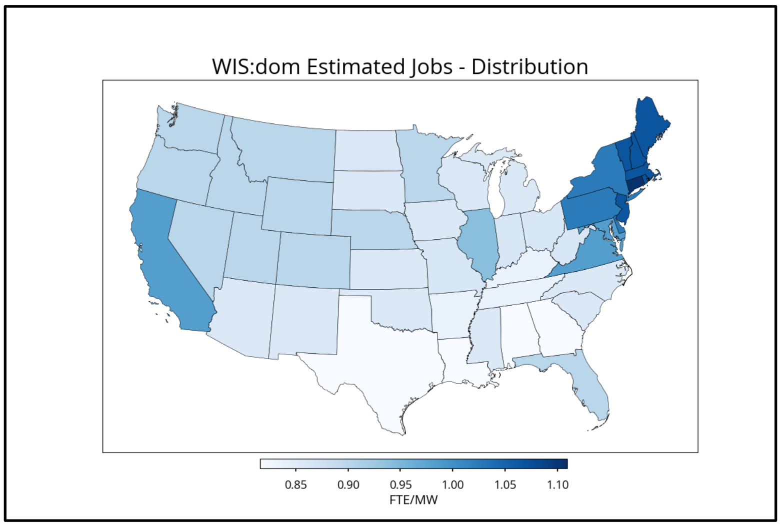


Figure 3.28: Employment per MW available from Distribution.

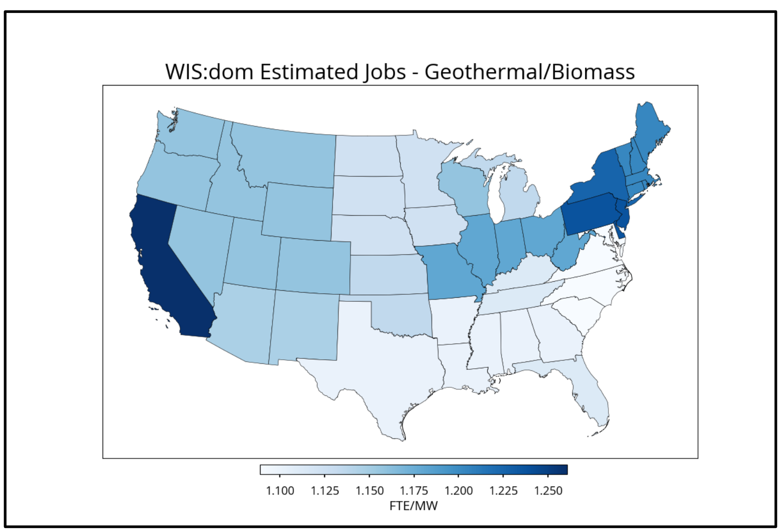


Figure 3.29: Employment per MW available from Geothermal and Biomass.

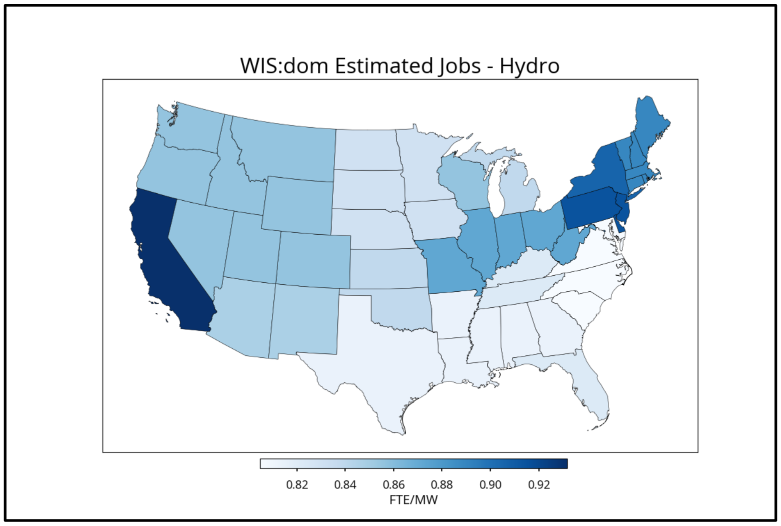


Figure 3.30: Employment per MW available from Hydro.

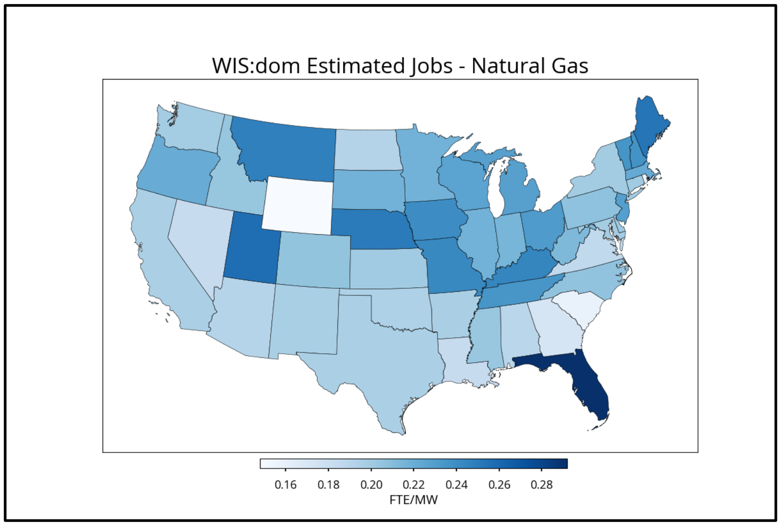


Figure 3.31: Employment per MW available from Natural Gas.

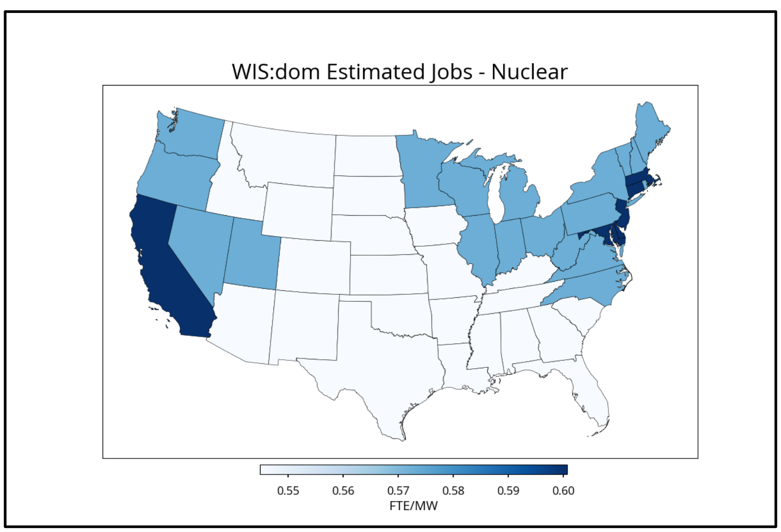


Figure 3.32: Employment per MW available from Nuclear.

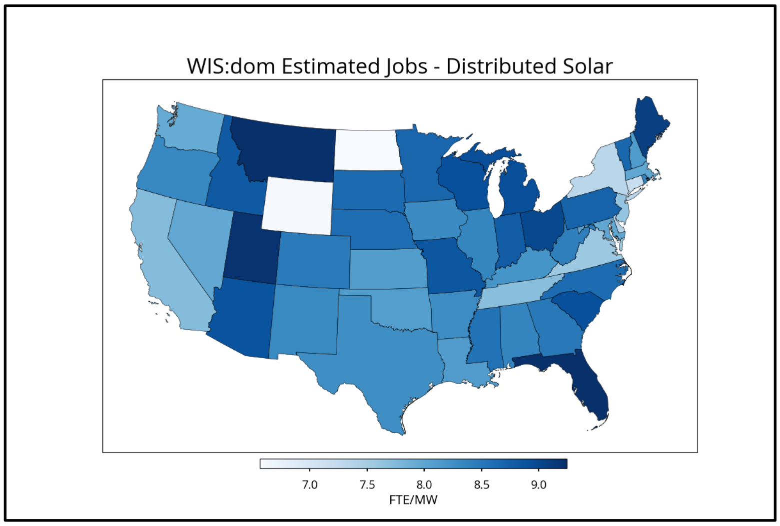


Figure 3.33a: Employment per MW available from Distributed Solar.

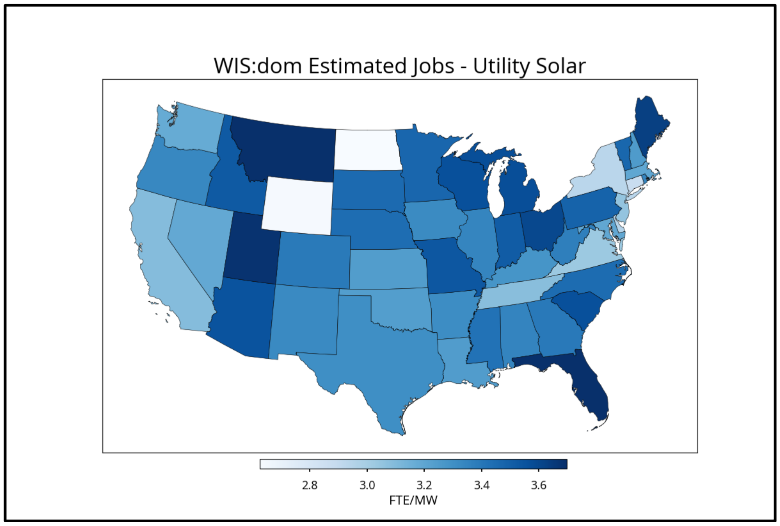


Figure 3.33b: Employment per MW available from Utility Solar.

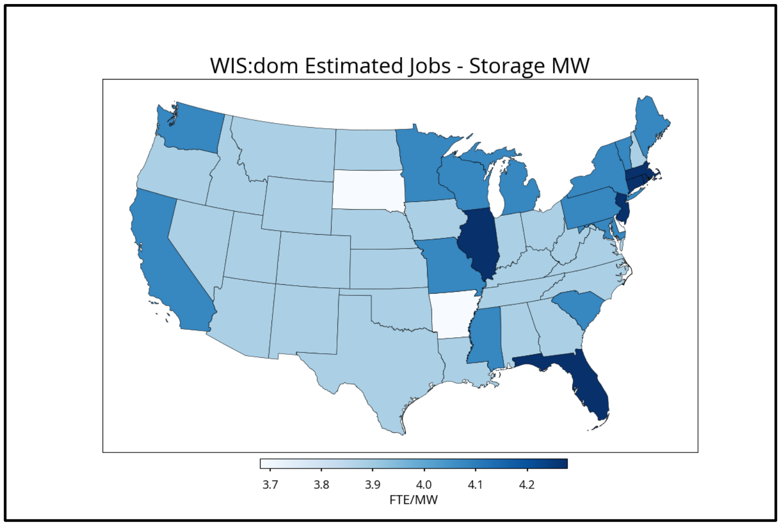


Figure 3.34: Employment per MW available from Storage MW.

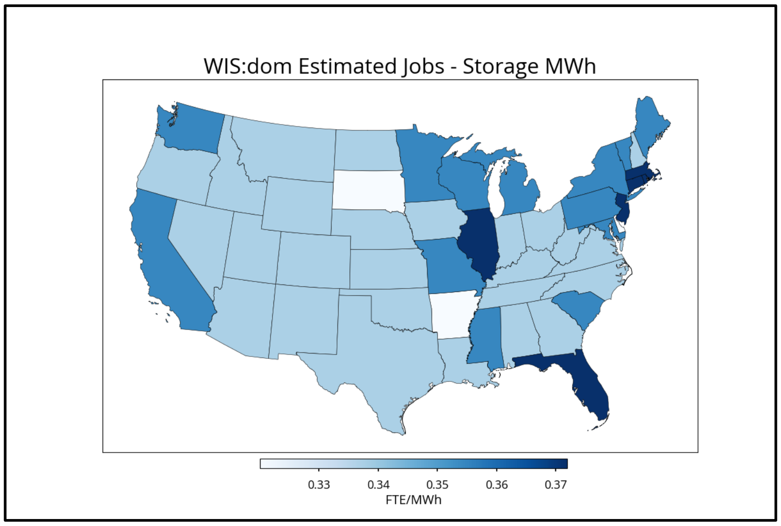


Figure 3.35: Employment per MWh available from Storage.

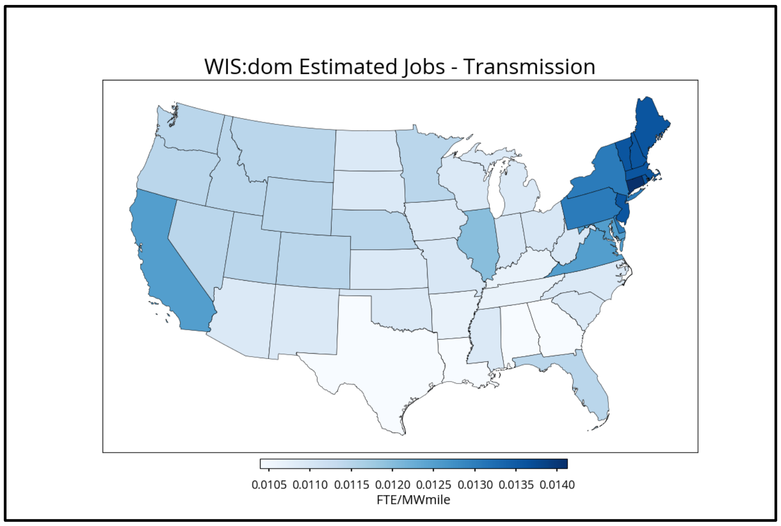


Figure 3.36: Employment per MW available from Transmission.

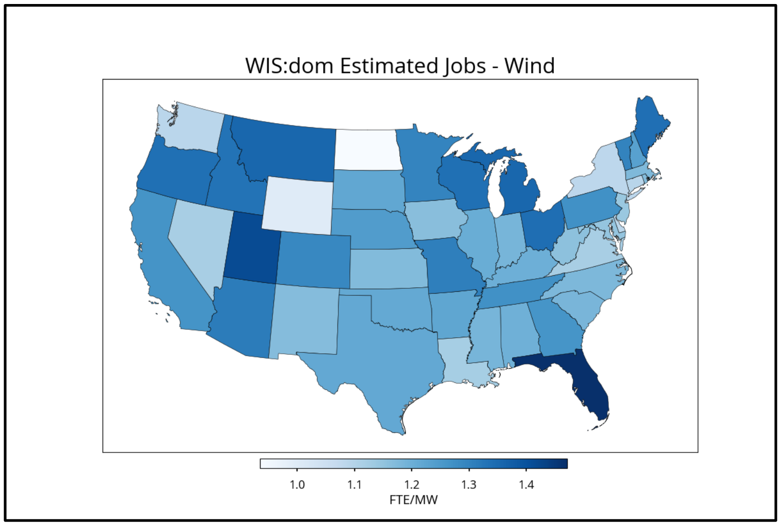


Figure 3.37: Employment per MW available from Wind.

3.5 Weather Analysis

This section looks at the weather data specific to the various regions of interest for this study. This will include SPP, Colorado and the WECC states (Washington, Idaho, Montana, Oregon, Wyoming, California, Utah, Colorado, Nevada, Arizona and New Mexico). This can provide insight into what, where, and why certain renewable sources, in particular, are selected by the model. The figures below demonstrate the average wind and solar capacity across all these regions by hour of the day. For wind, capacity factors for a 100-m hub-height wind turbine are used and for solar single axis tracking with latitude tilt technology is used. The load is also displayed for comparison. The series are shown for the average of the entire year and then the summer (June, July, August) and winter (January, February, March) seasons. The weather data considered here is from 2018.

Comparing the Figures 3.38a, 3.38b and 3.38c, it is seen that the solar resource in WECC is better than that in SPP. The Colorado solar resource reaches a higher average daily peak than SPP and is similar to the magnitude of the peak observed in WECC. It is the opposite for the wind resource where the wind resource in SPP is higher than that observed in WECC. The Colorado wind resource falls between that seen in SPP and WECC. Normalized load averages in both WECC and Colorado peak a few hours later in the day than in SPP. In general, the normalized load in Colorado is higher than that in both SPP and WECC throughout most hours of the day.

Unsurprisingly, Figures 3.38a, 3.38b and 3.38c also show the solar resource is both higher in peak and longer in duration during the summer. For wind, the reverse occurs where the resource drops during the summer and increases during the winter. The stronger jet stream and weather patterns in winter are apparent in the wind. Wind also exhibits a diurnal pattern where stronger resource is observed during the nighttime hours. This is a normal phenomenon for wind when the decoupling of the boundary layer near the surface at night allows for wind speeds to regularly increase due to less friction from the surface. For Colorado, in particular, nighttime hours can see around a 30% capacity factor from the wind resource on average for the whole year. For all regions, it is easy to see the complementary temporal patterns in the wind and solar resource. The peak normalized load for all regions is much higher in summer than in winter. The peak shape of the load is offset to the diurnal solar power pattern by a few hours in each region. Even with that, solar still has enough correlation with load during the day to be of use. In all regions as well, as solar decreases in the afternoon, wind resources increase to support the load in the late afternoon and evening.

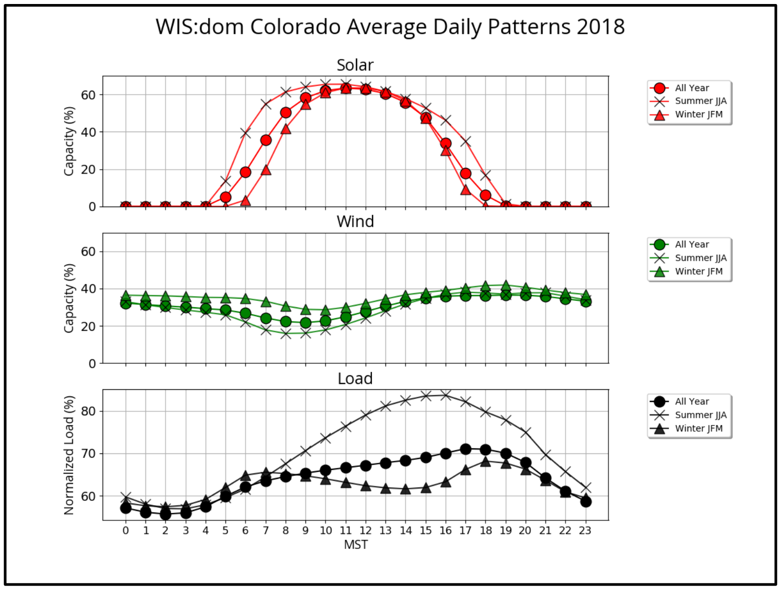


Figure 3.38a: The average solar (red) and wind (green) resource shown for the state of Colorado alongside the corresponding load (black) by hour of the day (MST). The circles show the hourly averages for the entire 2018 year. The other two series look at the summer (JJA) and winter (JFM) months of 2018.

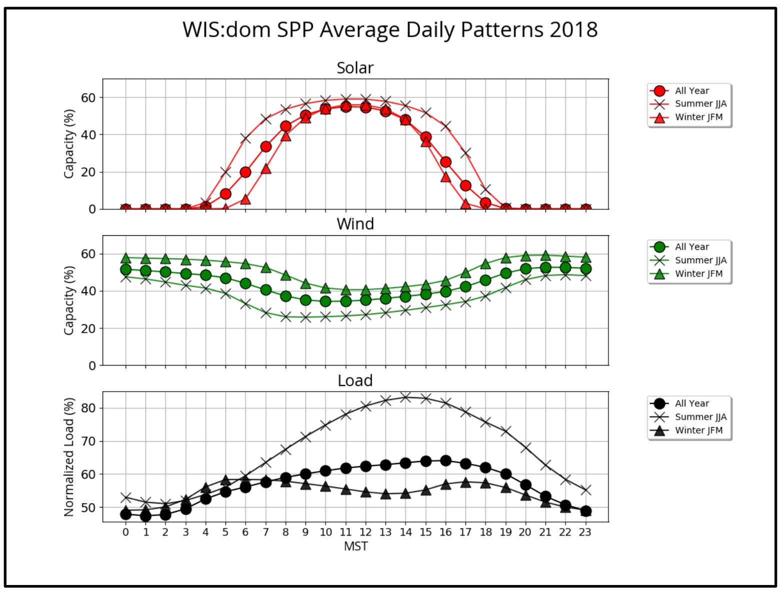


Figure 3.38b: The average solar (red) and wind (green) resource shown for the states in SPP alongside the corresponding load (black) by hour of the day (MST). The circles show the hourly averages for the entire 2018 year. The other two series look at the summer (JJA) and winter (JFM) months of 2018.

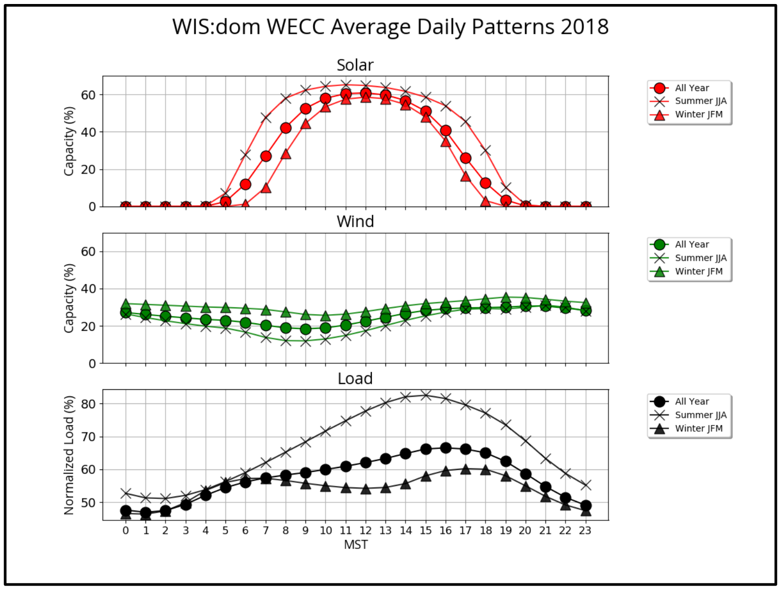


Figure 3.38c: The average solar (red) and wind (green) resource shown for the states in WECC alongside the corresponding load (black) by hour of the day (MST). The circles show the hourly averages for the entire 2018 year. The other two series look at the summer (JJA) and winter (JFM) months of 2018.

Figures 3.39a, 3.39b and 3.39c show how each parameter (solar, wind or load) changes against itself each season. The figures look at each season and overlaps the wind, solar and load data together for better comparison. Here it is easier to see how the solar resource peak compares to the load peak. In the yearly average, but especially in the summer months, the shapes of these two series show some alignment. The peak of the solar tends to occur on average a few hours in advance of the diurnal peak load for all regions. In winter, for all regions compared, the shape of the wind resource is highly correlated with the shape of the load. This, along with the anti-correlation of the wind and solar resource, shows the viability of wind as an asset alongside solar.

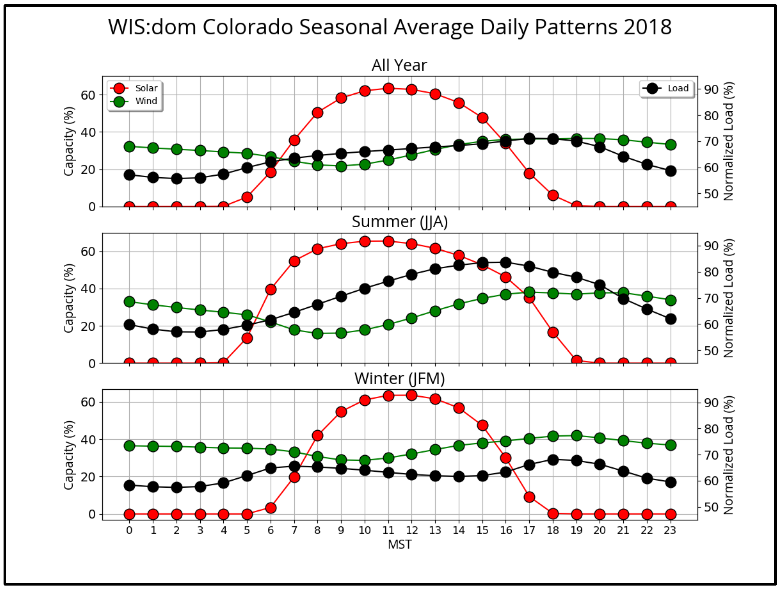


Figure 3.39a: The average solar (red) and wind (green) resource shown for the state of Colorado alongside the corresponding load (black) by hour of the day (MST). This is shown in seasonal groupings now; the entire 2018 year, the summer (JJA) of 2018 and winter (JFM) of 2018.

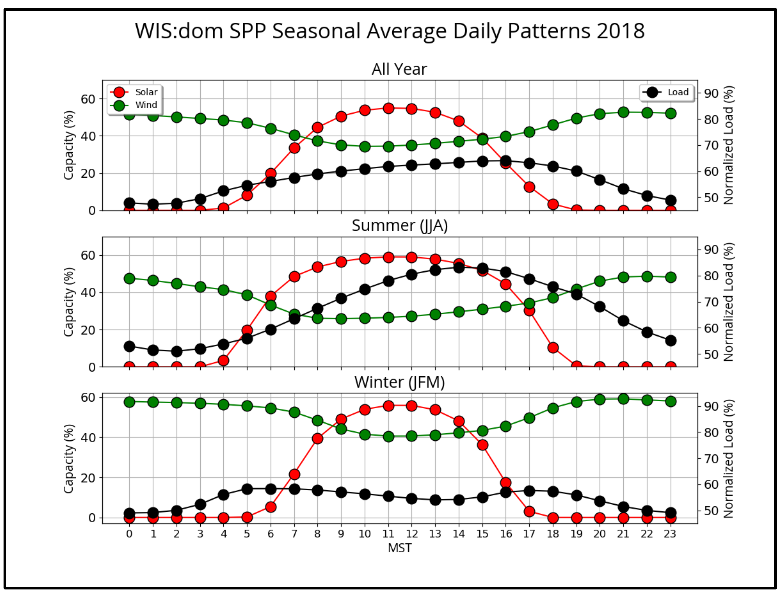


Figure 3.39b: The average solar (red) and wind (green) resource shown for the states in SPP alongside the corresponding load (black) by hour of the day (MST). This is shown in seasonal groupings now; the entire 2018 year, the summer (JJA) of 2018 and winter (JFM) of 2018.

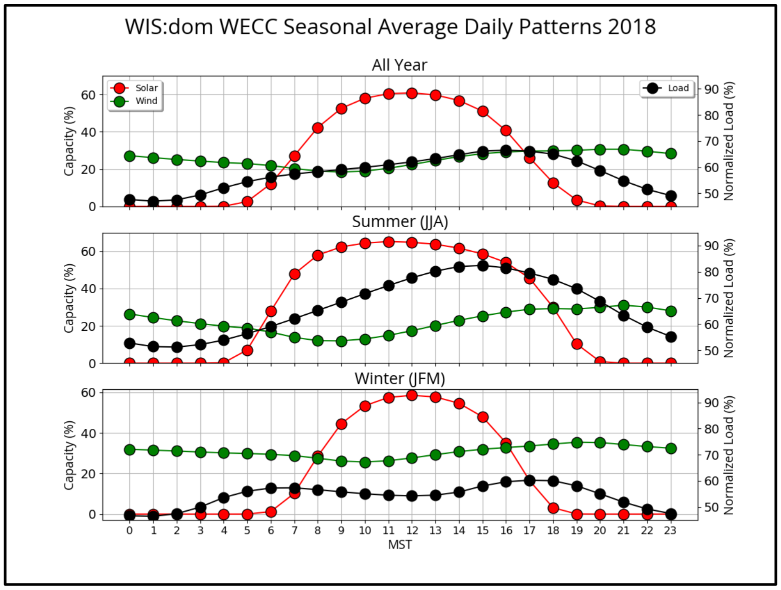


Figure 3.39c: The average solar (red) and wind (green) resource shown for the states in WECC alongside the corresponding load (black) by hour of the day (MST). This is shown in seasonal groupings now; the entire 2018 year, the summer (JJA) of 2018 and winter (JFM) of 2018.

VCE® investigated the wind and solar resources at different spatial granularities as well for this analysis. Figure 3.40 shows the average annual solar and wind resources throughout the day for WECC, SPP and Colorado. As mentioned previously, the daily solar resource in Colorado alone is larger than average for WECC as a whole. However, several individual states in the desert southwest have the highest solar resource (see Figure 3.42). The solar peak in Colorado is aligned temporally with that observed in the SPP states. The average WECC solar peak occurs roughly 1-2 hours after Colorado. This makes sense given the time zones covered in the WECC area. The wind resource in SPP, across all hours, overshadows the same resource in both Colorado and the wider WECC region (see Figure 3.43). This same analysis performed at state-level shows that Colorado is among the cluster of states with the highest solar resource (see Figure 3.44). Washington and North Dakota come in with the lowest solar peaks in 2018. From Figure 3.43, it is seen that Kansas had the highest nighttime peaks in wind generation and California had the lowest daytime lull in wind. Colorado wind falls solidly in the middle between the states in WECC and the states in SPP.

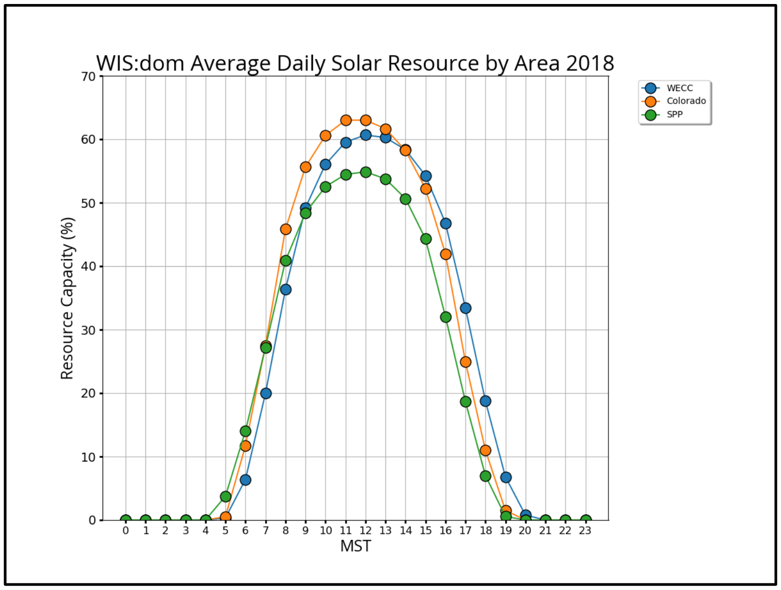


Figure 3.40: The 2018 average hourly solar resource capacity factors for modeled regions.

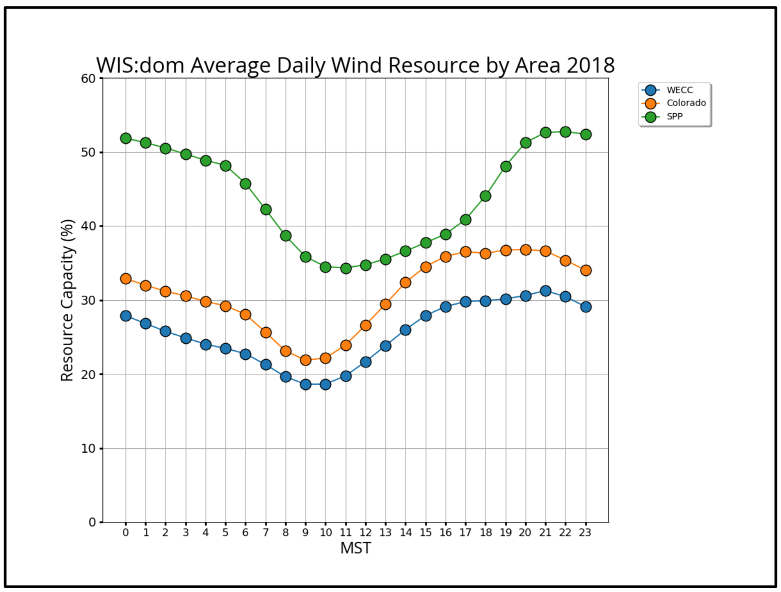


Figure 3.41: The 2018 average hourly wind resource capacity factors for modeled regions.

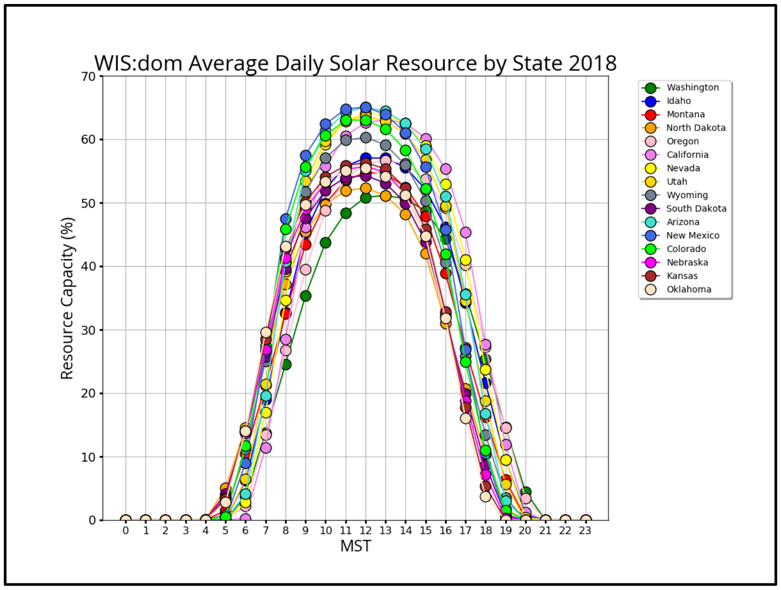


Figure 3.42: The 2018 average hourly solar resource capacity factors for modeled states.

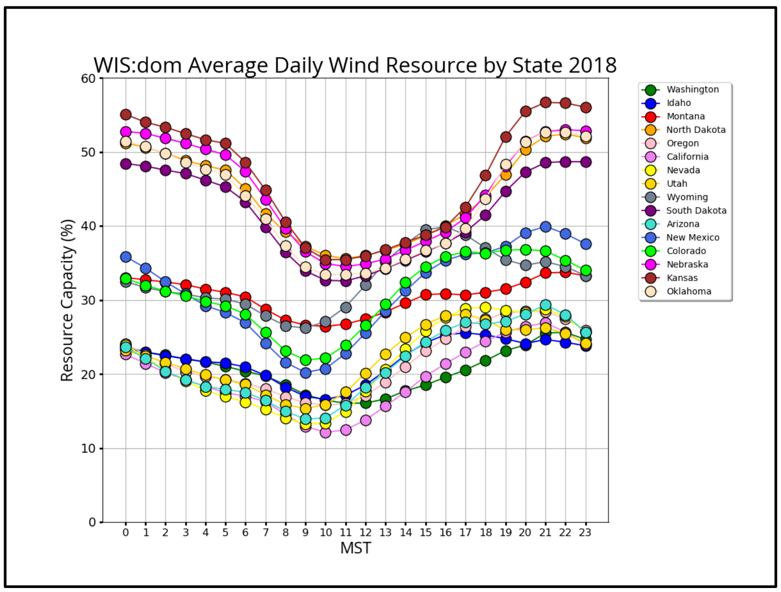


Figure 3.43: The 2018 average hourly wind resource capacity factors for modeled states.

Figures 3.44 and 3.45 show the average solar and wind resource respectively for all of 2018 by state. Nevada shows the highest solar resource in 2018 with North Dakota experiencing the lowest solar resource. For wind, Kansas shows the highest wind resource for 2018. However, all the Great Plains states exhibit high capacity factors for wind that year.

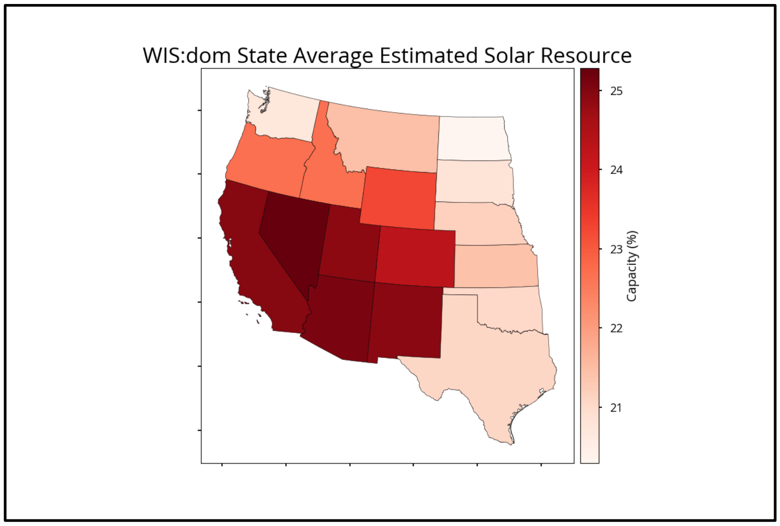


Figure 3.44: The average solar capacity factor (%) for 2018 by state in the West and Central US.

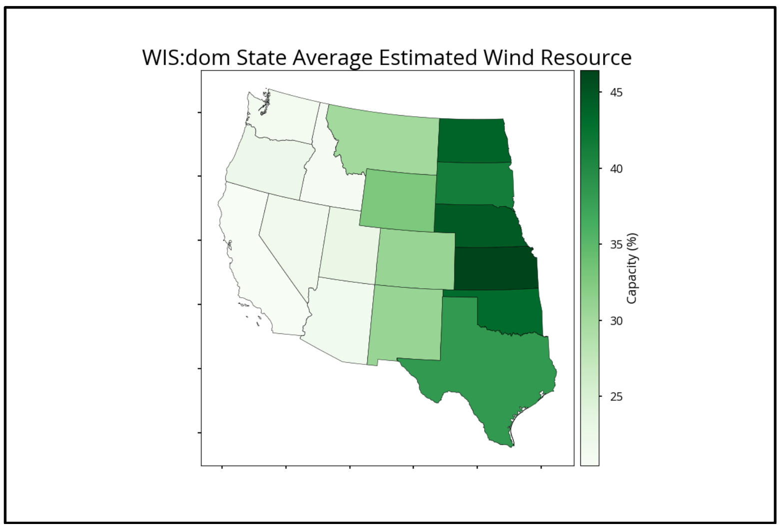


Figure 3.45: The average wind capacity factor (%) for 2018 by state in the West and Central US.

The 3-km HRRR weather model is utilized as the base for the weather inputs. Figure 3.46 shows a zoomed in look at the wind capacity resources at this granularity across the Western US. The Great Plains regions are home to the higher wind power resources. In general, wind power capacity factors decrease going from east to west looking at this half of the US. In 2018, Kansas had the highest average wind power capacity of all the states modeled. Figure 3.47 shows that the solar resource is highest in the desert southwest. The solar power capacity factors generally decreased going north and east in the states considered. Nevada has the highest solar power capacity in 2018. Utah, Colorado, California, Arizona and New Mexico are not far below Nevada in terms of available solar resource. Southern California has very high solar capability as well. This decreases in northern California, so the state as a whole comes in slightly lower than the other southwest states.

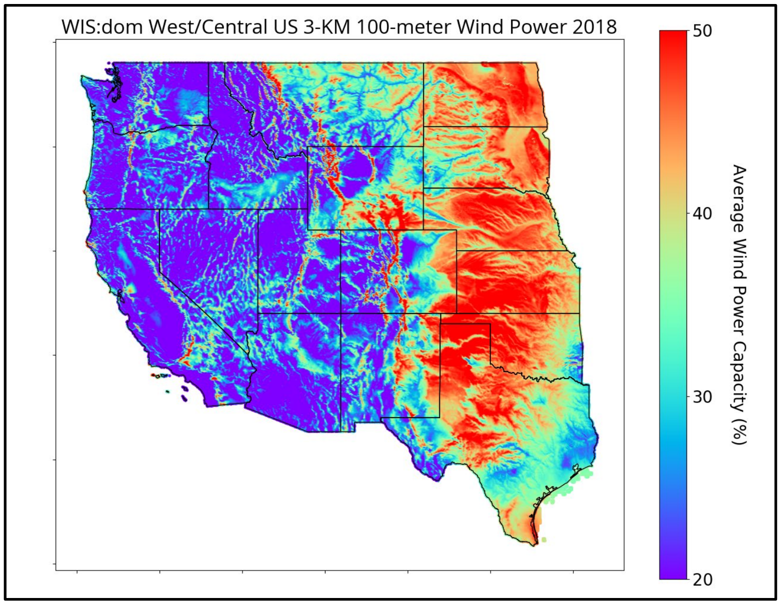


Figure 3.46: The 3-km 100-meter wind resource across the West and Central US in 2018.

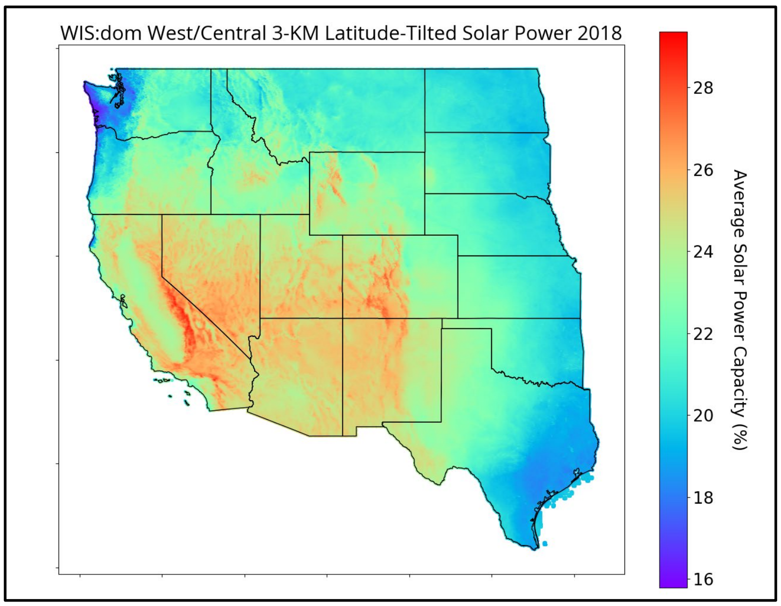


Figure 3.47: The 3-km latitude-tilted solar resource across the West and Central US in 2018.

VCE® analyzed a day of high wind during 2018 in Colorado. Figure 3.48 reproduced from the NOAA weather archives shows a surface weather analysis in April 2018. This was during a period that saw very high wind resource in Colorado. A cold front came across the Rocky Mountains and brought strong winds and pressure gradients both before and after frontal passage. Further, leeside cyclogenesis (the formation of large-scale winter storms that can occur on the downward wind side of a tall mountain range) brought strong southerly and easterly winds along the eastern plains of Colorado during this period. Figure 3.49a shows a time series view of the wind and solar resources alongside the normalized load in Colorado during such a high wind event. Wind capacity factors in Colorado reach over 90% at their peak during this period. During this same period, both WECC (Figure 3.49b) and SPP (Figure 3.49c) saw semi-similar patterns. WECC, in particular, was similar but temporally offset. Given that weather generally moves from west to east over the contiguous US, most of the WECC states experienced this increase in winds before Colorado did. However, on average, WECC did not see as high capacity factors as did Colorado itself. SPP also generally showed similar temporal patterns this week in wind as Colorado (simplistically speaking). All of SPP reached over an 80% wind capacity factor.

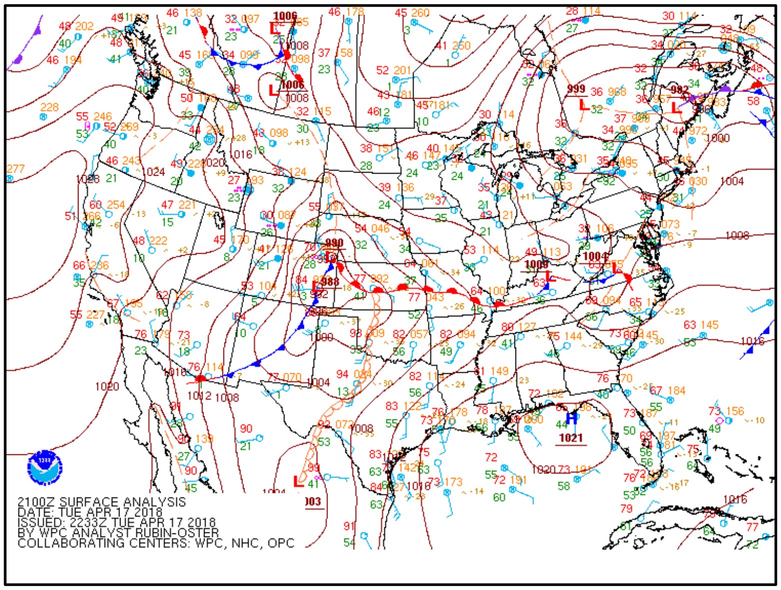


Figure 3.48: Surface Weather Analysis Plot from April 17th, 2018 at 21 UTC. This surface plot is provided from NOAA's Weather Prediction Center Archives (https://www.wpc.ncep.noaa.gov/archives/web_pages/sfc/sfc_archive.php).

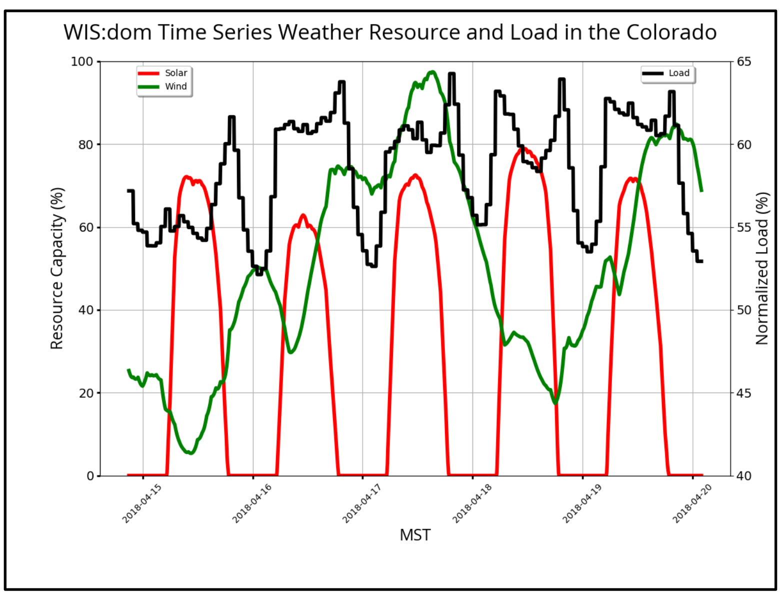


Figure 3.49a: A time series of the average solar (red) and wind (green) resources across Colorado in April 2018. The load (black) is also plotted. This was one of the highest wind periods from 2018.

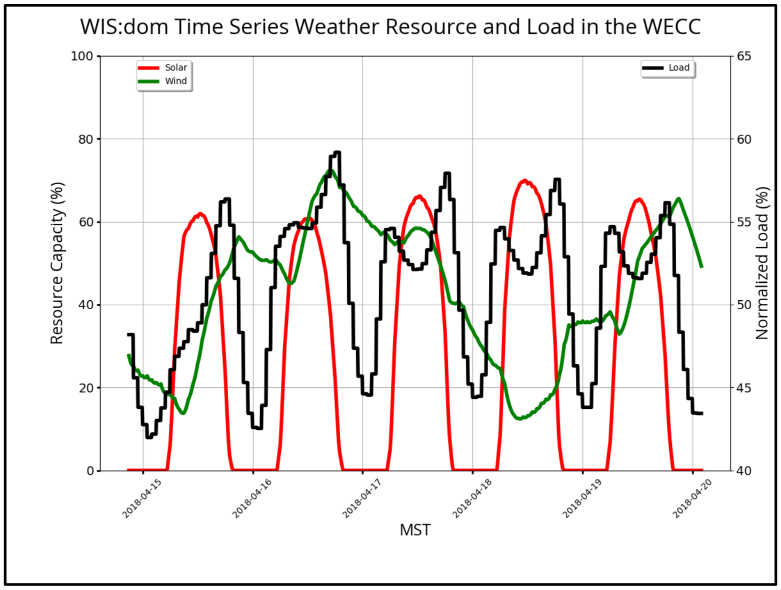


Figure 3.49b: A time series of the average solar (red) and wind (green) resources across WECC in April 2018. The load (black) is also plotted. This was one of the highest wind periods from 2018.

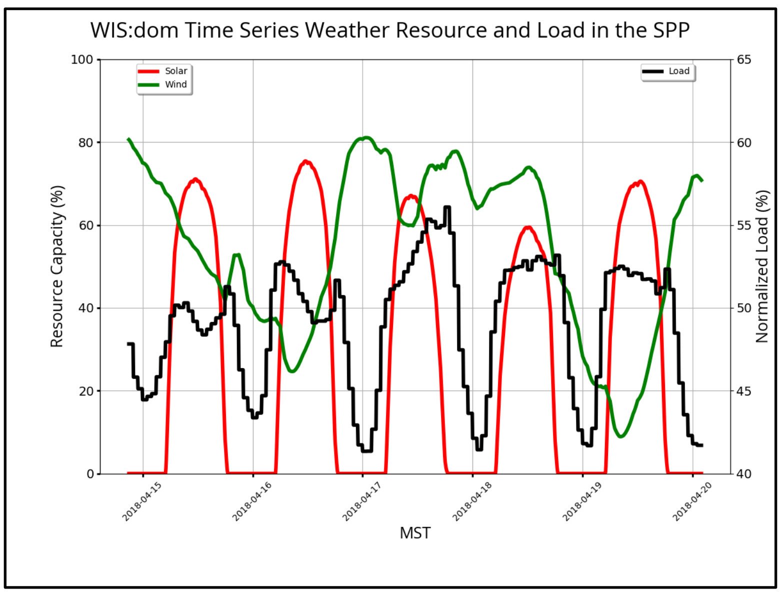


Figure 3.49c: A time series of the average solar (red) and wind (green) resources across SPP in April 2018. The load (black) is also plotted. This was one of the highest wind periods from 2018.

Next, Figure 3.50 shows a September week that had some of the lowest wind observed in 2018 for Colorado. The diurnal patterns in wind speed is apparent. Even though the wind resource is not too high during this period, it still remains anti-correlated to solar which can help bring value in the model during evening and nighttime hours.

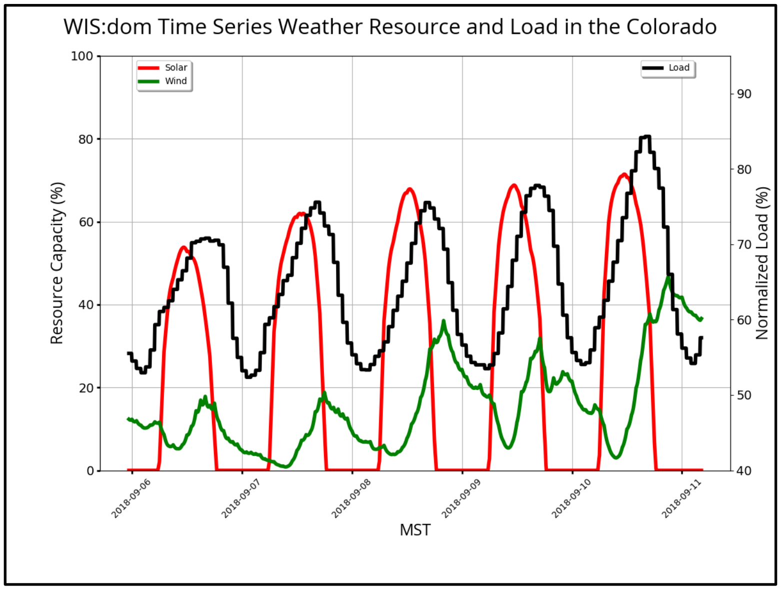


Figure 3.50: A time series of the average solar (red) and wind (green) resources across Colorado in September 2018. The load (black) is also plotted. This was one of the lowest wind periods from 2018.

VCE further studied the correlation between each of these three regions (Colorado, SPP and WECC) based on the renewable resource. Figure 3.51a and 3.51b show scatter plots between Colorado and SPP and Colorado and WECC for the wind and solar resources experienced in 2018. The wind resource in Colorado is generally more correlated with that observed in SPP than in WECC. This shows there is benefit Colorado wind can bring to the western states as there are more times where different weather patterns are affecting the areas. Colorado's solar resource is marginally more correlated with solar in SPP than in WECC as well. This generally points to the diurnal Colorado solar peak corresponding well temporally to when solar peaks in SPP. The solar output in WECC peaks about 1-2 hours following Colorado and SPP. Colorado's solar resource is strong, especially compared to the SPP states. In WECC, the southwest states have only a slightly higher solar resource than Colorado. From a renewable resource perspective for Colorado, there is wind competition to the east and solar competition from the west.

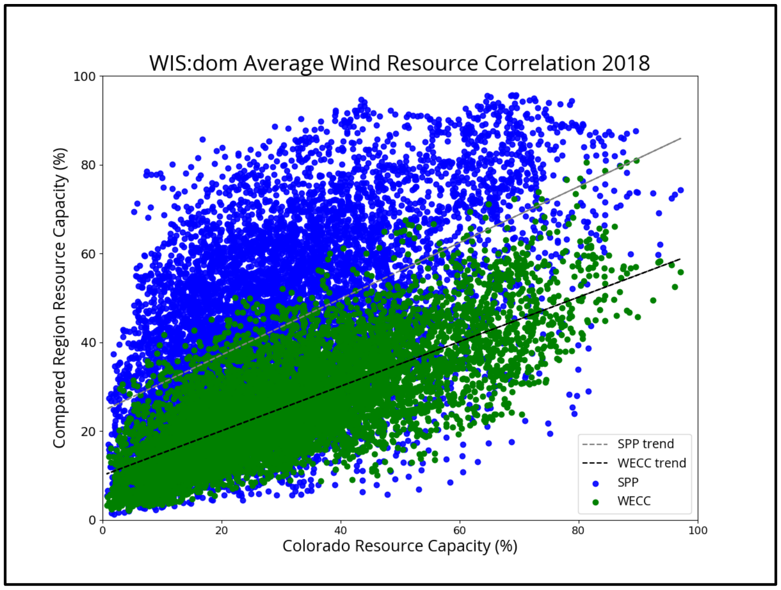


Figure 3.51a: A scatter plot of the 2018 wind capacity factors (%) in Colorado versus SPP in blue and WECC in green. Basic trendlines are added for comparison.

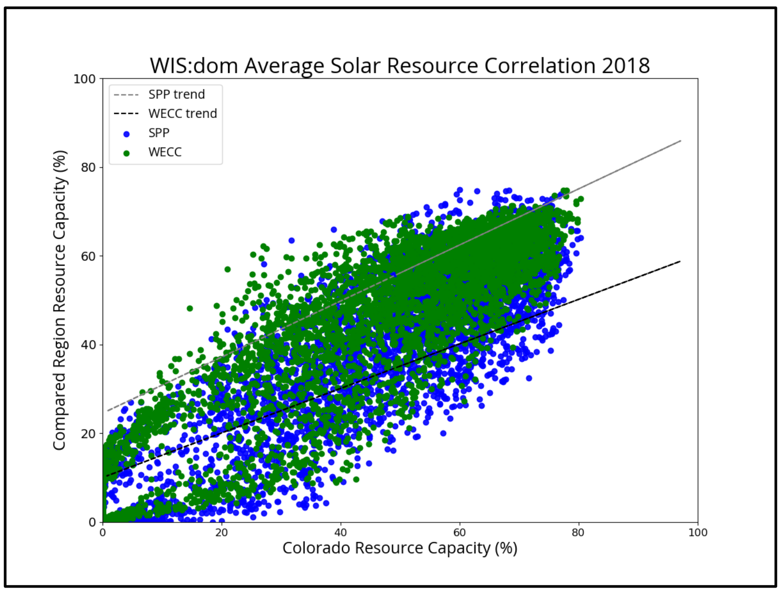


Figure 3.51b: A scatter plot of the 2018 solar capacity factors (%) in Colorado versus SPP in blue and WECC in green. Basic trendlines are added for comparison.

Figures 3.52a and 3.52b show histograms of wind and solar capacity factors for each region considered. For wind, it is observed that the average wind resource in WECC most often has a capacity factor value around 20%. The highest the WECC wind resource shows is around 80%. Colorado observes periods of wind capacity factors between 20-40% most often. It also sees additional hours of higher wind capacity factors, sometimes reaching over 90%. SPP experiences wind capacity factors most often around 35%. The number of hours this region experiences wind capacity factors over 40% is far higher than either WECC or Colorado. The solar capacity factors most often fall around 60% in WECC. For Colorado, the most common solar capacity factor is just slightly higher than WECC. This again shows the high solar resource Colorado has. SPP capacity factors most often fall around 50%. Note that the nighttime hours were removed from solar when looking at the histogram since zero is the most common value for solar.

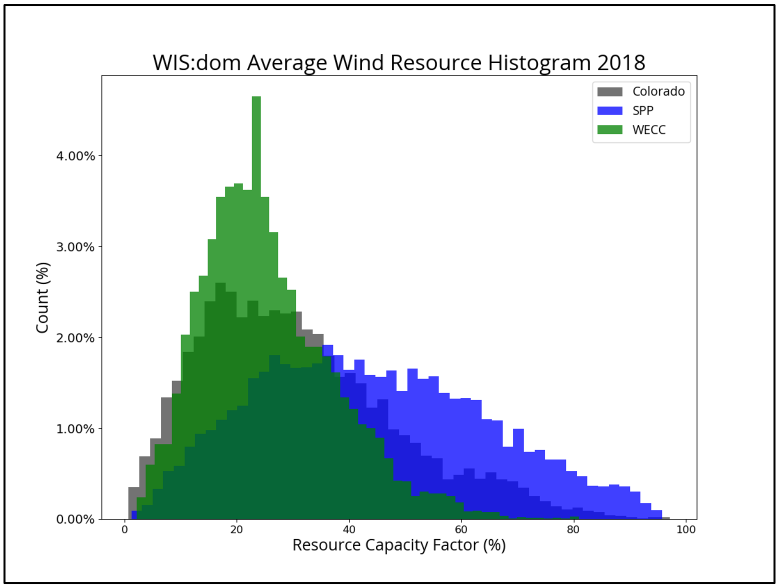


Figure 3.52a: A histogram plot of the 2018 wind capacity factors (%) in Colorado (gray), SPP (blue) and WECC (green).

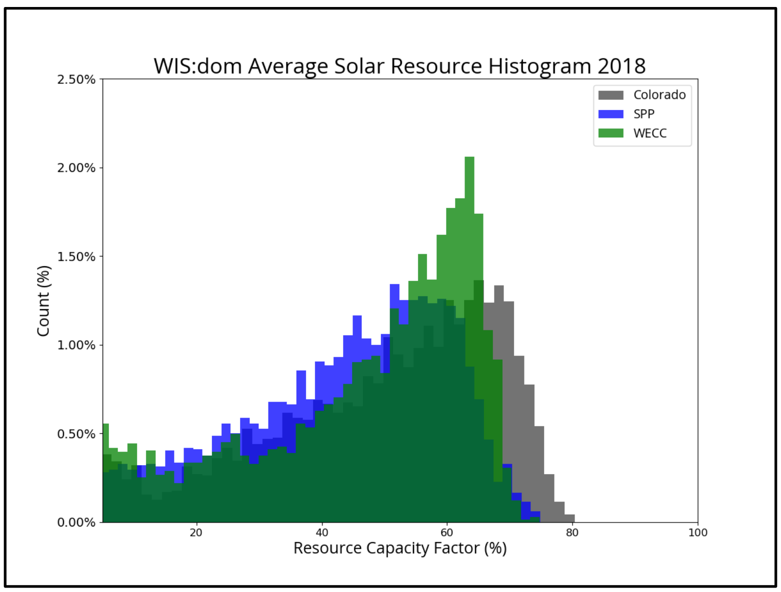
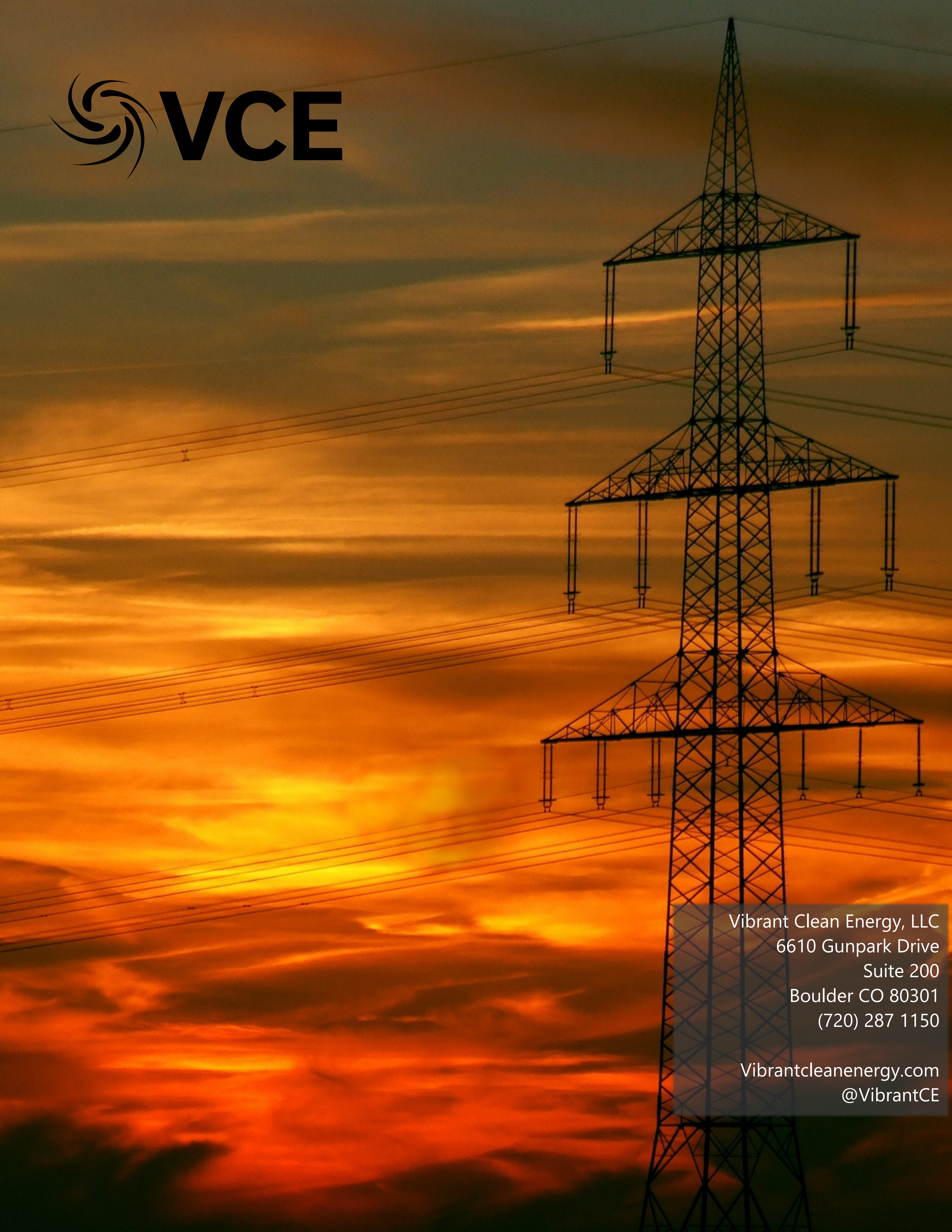


Figure 3.52b: A histogram plot of the 2018 solar capacity factors (%) in Colorado (gray), SPP (blue) and WECC (green).



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