Executive Summary

The economic development rate (EDR) is designed to encourage economic growth in Colorado by offering a reduced rate to new and expanded facilities with large electric loads. This reduced rate will improve Colorado's energy cost competitiveness, and will encourage companies with high electricity costs to locate in Colorado area. Prior to determining the rate, future transmission and distribution upgrades must be anticipated and estimated in order to establish an incremental cost of new load. This analysis ensures that EDR customers will pay for the costs of the investments their new loads require, and that offering the EDR is fair to all ratepayers.

A representative set of 10 substations were selected for this study, consisting of 17 substation transformers and 53 existing feeders. These substation sites are located across the service territory in high growth areas where land is available to support large facilities. For every year of the 10-year study period (2020 – 2029), one MW of coincident peak load was added to each substation – totaling 10 MW per year and 100 MW over the entire study period. As load was added to the system, transmission and distribution system overloads were monitored, and projects designed to mitigate the overloads. The incremental cost of mitigations to serve EDR customers was converted into a monthly cost per kW of new load. This monthly cost represents the marginal cost of capacity to serve the new EDR load.

It is evident through the power flow results that the transmission system is robust enough to accommodate the additional 100 MW of new load. The study results did not identify any overloads throughout the 10-year window of the study period in either the system intact or N-1 contingency state. It is concluded that the system is minimally impacted due to the geospatial diversity of the loads added at the 10 substation locations, given the assumptions of this study.

The distribution system is estimated to require $52.25 million in capacity projects over the study period, which is greater than the $7.5 million that would be required without this additional load. This incremental $44.75 million in cost translates into a $3.50 per kW per month rate.

Distribution

Background

Public Service Company of Colorado's ("Public Service" or the "Company") distribution system is made up of distribution substation and feeders and is primarily considered a summer peaking system. Public Service's distribution system will occasionally become overloaded when local loading exceeds the capacity of various system components. Such overloads are considered "N-0 Risks" – that is, risks to the system that exist under normal conditions.

Transformer Loadability

Each distribution substation contains one to three large power transformers ranging in size from 12.5 to 50 MVA. The load carrying capability of each of these transformers is calculated using ANSI/IEEE Standard C57.91-2011 "Guide for Loading Transformers" and stored in the

Company's common corporate Transformer Loading Database (TLD) which is maintained by the Substation Maintenance Department.

> *Example: Arrowhead Substation Bank #1 is a 115/12.5kV unit with a nameplate rating of 50 MVA. ANSI/IEEE calculations indicate that this transformer must be de-rated for altitude and summertime high temperature. After adjustment, the true load rating is 46.46 MVA. This adjusted rating would be used by the Planning Engineers as the official transformer limit.*

Distribution Feeder Loadability

Each distribution transformer will typically have from one to five feeders, each with the capability of handling anywhere from 5 to 19.5 MVA at voltages of 4, 12.5, 13.2, or 25 kV. Each distribution feeder is assigned a peak summer capacity, based upon detailed analysis to determine the *limiting factor* of each feeder. The analysis looks at the many different technical elements that make up a typical distribution feeder. These may include low side bus work, feeder circuit breaker, regulator, overhead conductor, underground conductor either directly buried or in duct, riser pole, gang or other switches, pad mounted switchgear, etc. The summer rating for each component is determined individually, and the rating of the limiting element is used as the official feeder capacity.

> *Example: The Mapleton 1752 13.2kV Feeder is served via 115/13.2kV Bank #1 at Mapleton Substation. The feeder circuit breaker is rated at 1200 amps. The conductor exiting the substation is a 2023-foot run of Kerite 1000 MCM 15kV copper conductor with 4/0 copper neutral installed within a 6-inch PVC conduit inside a concrete encased duct bank buried 4-foot deep, which has been rated at 740 amps using CYMCAP software to calculate cable ampacity. The insulated underground conductor within the duct bank transitions to overhead 795 kcmil 37-strand aluminum conductor (rated at 920 amps) using a single riser pole (rated at 940 amps) with parallel 600 amp switches (rated at 1200 amps). No other critical elements are part of this feeder. The lowest rated element in this case is the 1000 MCM conductor in duct rated at 740 amps. The limit for this feeder is therefore 740 amps, or 17.6 MVA at the 13.2kV distribution voltage.*

Distribution Loading Forecast

Each year after the peak summer loading season, Public Service Planning Engineers acquire peak MVA load readings for each transformer bank, and per-phase peak loads for each feeder throughout the entire Public Service system. The highest of three phase amp readings will determine the actual peak loading at each feeder, as Planning Engineers are looking for the "worst-case" loading scenario. Using historical actual annual peak loading levels since year 2004, and known load additions based on customer applications, each feeder is assigned a future growth rate.

Historically the sum of the actual feeder loads will be a bit more than the actual transformer bank load, as all feeders do not typically peak at the same time. The ratio of peak transformer to peak combined feeder loads is known as the "coincidence factor" for a given bank/feeders combination. The history of these factors are investigated and an appropriate "coincidence factor" for each bank is assigned. The forecasted transformer bank loads for each year into the future will be the summation of the individual forecasted feeder loads multiplied by the "coincidence factor" determined for each bank.

> *Example: The Derby 115/13.2 kV Bank #1 was loaded to a peak of 25,900 kVA during the summer of 2015. During the same summer, the three 13.2 kV feeders associated with this bank had peak loadings of 13506, 8560, and 5802 kVA based upon the measured high-phase ampere readings of 568, 360, and 244 amps respectively. The feeders total 27,867 kVA of load. In this case, the coincidence factor would be 25900 / 27867 or 0.94, which was also typical of previous years. Therefore, future forecasted bank loadings would be the sum of the individual forecasted feeder readings for a particular year multiplied by the "coincidence factor."*

A complete five-year distribution forecast is extrapolated using these historical values and growth rates. The previously calculated peak summer load ratings for each substation transformer and feeder are manually transferred and maintained in Itron database software known as the "Distribution Asset Analysis Suite" (DAA Suite) for comparison to the forecasted peak load values. The forecasted peak load for each transformer bank and feeder can be compared to the associated summer load ratings in each instance in order to determine the extent of overloaded facilities for five years into the future.

Distribution Overloads

Each time a forecasted transformer bank or feeder exceeds its normal rating, an overload occurs. These normal overloads are considered system "N-0 Risks" which will need to be addressed. When local loading exceeds the capacity of system components, appropriate measures ("mitigations") are determined to alleviate the overload using best engineering and industry practices.

Mitigation strategies will be used to eliminate the aforementioned N-0 Risks to the distribution system. Should these mitigation strategies include major capital expenditures, the associated project and work is scheduled into the five-year capital forecast for consideration during the yearly budget cycle. Mitigations typically consist of new substation transformers, new distribution feeders, and load transfers to move load from a heavily-loaded feeder or substation to a more lightly-loaded one. Note that "N-1 Risks", defined as overloads that would occur in the case of a failure of a single system component such as a feeder or transformer, are not mandated to be mitigated, and are usually mitigated based upon available funding.

Modeling and Assumptions

As described earlier, a representative set of 10 substations was selected for this study, consisting of 17 substation transformers and 53 existing feeders. For every year of the 10-year study period (2020 – 2029), one MW of coincident peak load was added to each of the 10 substations – totaling 10 MW per year and 100 MW over the entire study period. This load growth assumption is consistent with a high-end forecast of new load under the EDR rate. It is important to note that this 100 MW of peak load growth is in addition to the 1.63 percent forecasted peak load growth rate that is expected to occur if the EDR is not adopted.

To estimate the cost associated with adding the new EDR load, two scenarios were modeled – the baseline scenario without the EDR and associated load additions, and a scenario assuming the EDR is adopted and 100 MW of EDR load is added to the 10 substations. In each scenario, N-0 risks are monitored and mitigations are designed to alleviate the risks. The costs of mitigations were estimated based on historical project costs, and are summarized in Table 1. Costs were totaled for each scenario, and the difference in total cost between the two scenarios was calculated. This cost differential represents the incremental cost of distribution capacity associated with offering the EDR.

Table 1: Distribution Mitigations

Mitigation Name	Cost	Description	When Is It Used?
Load Transfer	$5,000	Permanent reconfiguration of distribution circuits to alleviate overload	When a feeder is overloaded but a neighboring feeder has capacity and reconfiguration is possible
New Distribution Feeder	$1,250,000	Construction of a new switchgear, feeder exit, and overhead distribution lines to serve additional load	When a feeder is overloaded, and there is not a neighboring feeder with capacity and/or reconfiguration is not possible
New Substation Transformer	$6,500,000	Installation of a new substation transformer, including changes to bus work and protection system	When a substation transformer is overloaded and there is not a neighboring transformer with capacity and/or reconfiguration is not possible

Other assumptions are summarized below:

1. Capacity was adjusted from kW at the customer site to kVA at the substation based on a historical average power factor of 0.98 lagging and average distribution losses of 6 percent.
2. Operations and maintenance costs are assumed to be 7 percent of the capital costs per year.
3. Load additions were assumed to be evenly spaced across each feeder at a substation, e.g. a substation with five feeders would have 200 kW added to each feeder per year due to EDR customers.
4. Mitigations are limited to traditional wires options, and non-wires alternatives such as battery energy storage systems, photovoltaic systems, demand response, or energy efficiency were not considered.

Results

The results of the study are summarized in Table 2.

Table 2: Scenario Cost Comparison

Substation	Base Case Mitigations	Base Case Costs	EDR Case Mitigations	EDR Case Costs	Incremental Costs
Argo	New Feeder	$1.25M	New Feeder	$1.25M	$0
Arrowhead	New Feeder	$1.25M	Three New Feeders	$3.75M	$2.5M
Chatfield	None	$0	Two New Feeders	$2.5M	$2.5M
Imboden	None	$0	New Feeder	$1.25M	$1.25M
Louisville	New Feeder	$1.25M	Two New Feeders	$2.5M	$1.25M
Monaco	Load Transfer	$5k	New Bank + Three New Feeders	$10.25M	$10.245M
Murphy Creek	Two New Feeders	$2.5M	New Bank + Five New Feeders	$12.75M	$10.25M
Picadilly	None	$0	New Bank + Two New Feeders	$9M	$9M
Surrey Ridge	None	$0	New Bank + New Feeders	$7.75M	$7.75M
Thornton	New Feeder	$1.25M	New Feeder	$1.25M	$0
TOTAL		**$7.51M**		**$52.25M**	**$44.75M**

Overall, the incremental cost of system investments to support 100 MW of EDR load growth totals to $44.75M over the 10-year period. This translates in to a revenue requirement of $1.92 per kW month after dividing by the 10 years and the 100 MW load growth. After adjusting for operations and maintenance expenditure of 7 percent per year, the total cost is $3.50per kW month. This represents the marginal cost of distribution capacity, translated into a monthly rate.

Transmission

The transmission system is made of many miles of high voltage lines and a variety of equipment, which ultimately tie the network generation resources to the distribution system loads. The transmission system is typically designed and constructed to handle years of future load growth. The Transmission Planning department remains informed of the transmission system's performance through its annual updates to load and generation forecasting as well as its annual analysis of the system as required by the North American Electric Reliability Corporation (NERC). Transmission Planning reviews the system performance on a near term, 2 to 5 year window and a long term window of 5 to 10 years. It is Transmission Planning's intent to mitigate any overloads, system constraints or deficiencies years prior to them becoming an issue on the transmission system.

Modeling and Assumptions

The new load will be referred to as the EDR load throughout this document.

Ten substation locations were selected which would accommodate the new EDR load requests. These sites were determined based on the likelihood that a customer may seek to locate their facilities in the surrounding area. Sites were selected based on the following factors:

- Level of interest based on Economic Development team input
- High growth area trends
- Distribution and Transmission Planner input
- Availability of land to support large facilities
- Diversification throughout the service territory

The following 10 substations were selected. A list of MW loads is included in an Appendix A. Each substation load was increased by one MW of load per year for 10 years. The existing load value at each substation was used as the initial benchmark value.

- Picadilly
- Surrey Ridge
- Chatfield
- Imboden
- Louisville
- Arrowhead Lake
- Thornton
- Murphy Creek
- Argo
- Monaco

The existing load power factor was maintained throughout the study. For example, if the existing power factor was 0.98 then the real power load was increased by 1 MW and the reactive power was determined based on the existing 0.98 power factor. This was done to assume that the characteristics of the new loads remain similar to the existing loads at the any given substation.

Further, it is assumed that the loads in a given area, to some degree will have similar qualities. As an example, industrial areas will attract new industrial customers while areas with heavy residential loads will attract other residential loads. Local ordinances may also drive this distinction.

Study Process

The study was conducted using PSS/E software Version 34.

The benchmark case was established using a WECC 2020HS3 base case. This case will reflect a heavy summer load and associated dispatch per Transmission Planning’s Variable Energy

Resource guidelines. A steady state and contingency analysis was run on the benchmark case to ensure that there were no overloads with the system intact as well as under an N-1 condition. A contingency analysis will remove a single element from the system, i.e. transformer, transmission line, generator, and so on for each element in the system. The software then solves the case and repeats the process of removing single elements followed by solving for power flow. Transmission Planning complies with all NERC standards and routinely reviews the case models for system intact and N-1 contingencies. This effort established the baseline for the rest of this study.

Stepping into the first iteration, the EDR loads (10 MW total) were added to the 2020 heavy summer case. Each of the 10 sites were increased by 1 MW. The system was then solved to identify any steady state overloads. Further, a contingency analysis was performed on the model to identify any N-1 contingencies. The results were evaluated for accuracy and to determine if there were any system issues related to the additional 10 MW of load.

Prior to performing the next iteration, the system load was adjusted to reflect a 2021 heavy summer base load. This was done to account for the load growth forecasted in Public Service's native load. No modifications were made to the model topology. In further iterations, the generation was dispatched at a higher level to maintain a generation to load balance. Without this balance, the system will either fail to solve or the scheduled power imports from other areas would begin to diverge from the original set point. These steps were repeated for each case year, 2020 through 2030.

Results

The results of the power flow studies indicate that the addition of 100 MW of load does not adversely impact the transmission system in either a steady state or N-1 contingency state over the course of the next 10 years. Further, there were no transmission upgrades attributed to the additional 10 MW at each of the 10 substation locations. It is concluded that the existing transmission system and associated facilities are capable of handling the additional 100 MW of EDR loads given the assumptions stated previously in this report.

Appendix A

Table 3: Transmission System Loads in Real Power (MW)

	Study Year											
Location	**2020 Benchmark**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Picadilly	33.20	34.20	35.20	36.20	37.20	38.20	39.20	40.20	41.20	42.20	43.20	44.20
Surrey Ridge 230kV P1	42.27	43.27	44.27	45.27	46.27	47.27	48.27	49.27	50.27	51.27	52.27	53.27
Chatfield 230 P1	28.90	29.90	30.90	31.90	32.90	33.90	34.90	35.90	36.90	37.90	38.90	39.90
Imboden	2.91	3.91	4.91	5.91	6.91	7.91	8.91	9.91	10.91	11.91	12.91	13.91
Louisville P1	20.95	21.95	22.95	23.95	24.95	25.95	26.95	27.95	28.95	29.95	30.95	31.95
Arrowhead Lake 115 P2	27.64	28.64	29.64	30.64	31.64	32.64	33.64	34.64	35.64	36.64	37.64	38.64
Thornton 115 P1	12.68	13.68	14.68	15.68	16.68	17.68	18.68	19.68	20.68	21.68	22.68	23.68
Murphy Creek 230 P2	17.33	18.33	19.33	20.33	21.33	22.33	23.33	24.33	25.33	26.33	27.33	28.33
Argo 115 P2	17.21	18.21	19.21	20.21	21.21	22.21	23.21	24.21	25.21	26.21	27.21	28.21
Monaco 230 P1	33.59	34.59	35.59	36.59	37.59	38.59	39.59	40.59	41.59	42.59	43.59	44.59