U.S. DEPARTMENT OF
ENERGY

Dynamic Line Rating

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Executive Summary

The electric grid is a complex system-of-systems that is responsible for providing safe, reliable, and cost-effective electricity to customers. If a transmission system component, such as an overhead line, is operating at its physical limit, system operators may choose to run a more expensive generator over a less expensive one in order to meet safety and system reliability standards. The events and costs associated with the suboptimal commitment and dispatch of generators is known as congestion. Congestion costs can be quite substantial; the sum of real-time congestion cost among major U.S. system operators in 2016 was $4.8 billion.

Traditional solutions to alleviating congestion include expanding, upgrading, or rebuilding the electric infrastructure. While these long-lead-time solutions may be needed in the long term, new and innovative technologies such as dynamic line rating (DLR) may provide congestion relief in the near term at lower expense. DLR systems are one of many options for addressing grid congestion; other solutions such as power-flow controllers, energy storage, distributed energy resources, and demand response also play key roles in modernizing the grid. An additional benefit of implementing DLR is increased situational awareness of the transmission system and the potential for condition-based monitoring of transmission lines.

The maximum power flow capacity on a transmission line is limited by heating considerations to maintain safe and reliable operating conditions. These static line ratings (SLRs) are usually calculated using conservative assumptions about the transmission-line operating environment, producing an inflexible constraint that does not take advantage of changing or favorable environmental conditions (e.g., wind cooling) that allow for greater transmission usage. DLR is a blanket term for the many different technologies and methodologies for determining conductor thermal ratings in a more-dynamic fashion using improved, more granular, or real-time data. At its core, DLR systems help system operators determine the prevailing current-carrying capacity limits of transmission lines to relax constraints based on SLRs.

Over the past several decades, a diverse set of technologies, methods, and systems have been developed to enable DLR. Each system and method has advantages and disadvantages when it comes to accuracy, reliability, capital cost, ease of installation and integration, and maturity. Despite DLR's potential for realizing cost savings and its ability to increase grid reliability and resilience, several challenges remain that prevent its widespread adoption. Implementation of DLR must ensure that new hazards are not created and be tempered with consideration for other system limitations and the potential for unintended consequences.

The U.S. currently lags behind other countries in the deployment of some advanced transmission technologies, such as DLR. One of the variables is the difference in regulatory environments; the U.S. provides transmission owners little incentive to deliver more power over existing lines or to reduce transmission congestion. Additionally, wholesale electricity markets play an important role in guiding the operating, planning, and investment decisions of asset owners and developers. Broad adoption of DLR will influence the performance of electricity markets, impacting the profitability or viability of specific generation sources. While the impact of DLR schemes on different generation technologies cannot be generalized, there are instances where specific sources can be advantaged or disadvantaged.

Overall, experience with DLR pilot studies and demonstrations have shown capacity increases, but the outcomes are difficult to extrapolate beyond the targeted lines. Numerous power grid stakeholders have also expressed support for DLR, but technical, market, and regulatory challenges remain that must be addressed to facilitate broader adoption. Further research is needed to better understand the economic benefits, costs, and impacts of wide-spread DLR adoption, especially at the regional or national level. Additional demonstrations and pilot studies can also provide utilities and other stakeholders with increased confidence in DLR methods and systems, reduce technology risk and uncertainty, and help ascertain the value of ancillary benefits such as improved situational awareness.

Abbreviation Reference

AAR	Ambient Adjusted Rating
AEP	American Electric Power
CAISO	California Independent System Operator
CIGRE	International Council on Large Electric Systems
DERs	distributed energy resources
DLR	dynamic line rating
DOE	Department of Energy
DTE	Detroit Edison (DTE Energy)
ERCOT	Electricity Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
ISO	independent system operator
ISO-NE	Independent System Operator New England
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability Corporation
NYISO	New York Independent System Operator
NYPA	New York Power Authority
REE	Red Electica de Espana
ROE	return on equity
RTE	Réseau de Transport d'Électricité
RTO	regional transmission organization
SCADA	supervisory control and data acquisition
SIL	surge impedance load
SLR	static line rating
TCF	transmission capacity forecasting
TDU	transmission and distribution utility
WOW	Wind on Wires
WPPI	Wisconsin Public Power Inc.

DYNAMIC LINE RATING

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II. Introduction

The electric grid is a complex system-of-systems that is responsible for providing safe, reliable, and cost-effective electricity to customers. Developed and built over the last 125 years, the U.S. electric power system has been called the biggest machine in the world. The electric transmission and distribution infrastructure and the energy delivery it facilitates represent an essential fabric of the modern economy. Whether the grid is powering manufacturing and essential health services or our computers and cell phones, its omnipresence is felt most when it suddenly fails. Recently, investments in the grid have focused on improving its reliability, efficiency, and resiliency to meet the growing dependence on electricity across all sectors. This is a complicated task where generation and use must be balanced continuously, the ability to store electricity cost-effectively is limited, and energy consumption patterns are ever-changing.

To serve our expectation of continuous access to electricity, a collection of generators, towers, wires, transformers, switches, and poles were erected and stitched together. The electric power system is typically divided into the categories of generation, transmission, distribution, and end-use. In addition to the physical infrastructure, a centralized control paradigm was developed where large remote generators are coordinated and dispatched to ensure the reliable delivery of electricity to end-users through a vast network of high-voltage transmission lines and lower-voltage distribution systems. Balancing authorities and system operators have been tasked with the dispatch of generators to meet all loads while ensuring reliability and minimizing costs, a process known as security-constrained economic dispatch.

If a transmission system component, such as an overhead line, is operating at its physical limit, balancing authorities may choose to run a more expensive generator over a less expensive one in order to meet safety and system reliability standards. The events and costs associated with the suboptimal commitment and dispatch of generators are known as congestion [1]. Balancing authorities and system operators attempt to mitigate congestion by forecasting demand and generator availability in the short term (e.g., through day-ahead and hour-ahead markets) and identifying system needs in the long term (e.g., through multi-year resource, transmission, and distribution planning).

Ultimately, the goal of the electric grid is to deliver safe, reliable, and cost-effective electric power. For each part of the system, there are numerous tools, technologies, and approaches to help accomplish this goal. In the distribution system, vegetation management and distribution automation are used to prevent and recover from interruptions. In the transmission system, a variety of contingencies are analyzed and planned for while phasor measurement units provide wide-area situational awareness. Dynamic line rating (DLR) is one of several tools that can help address challenges with transmission operation, especially congestion management.

State of the U.S. Electric Grid

The U.S. electric grid contains more than 200,000 miles of high-voltage transmission lines and roughly 5.5 million miles of local distribution lines that operate within a patchwork of Federal, State, Tribal, and local regulatory jurisdictions. However, the reliability of the bulk power system (i.e., large generators and the transmission network) generally fall under the purview of the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC), which issue and enforce mandatory reliability standards [2]. Several professional organizations, such as the Institute for Electrical and Electronics Engineers (IEEE), International Electrotechnical Commission (IEC), and the International Council on Large Electric Systems (CIGRE), also issue guidelines and technical standards. These various standards provide the basis for the bulk power system that is key to ensuring the safe and reliable delivery of electricity.

Climate in the U.S. spans a vast spectrum, ranging from tropical to subarctic to desert, depending on location. This means the electric power system experiences many different temperatures and weather conditions daily and throughout the seasons of the year. Additionally, the demand for electricity also changes by hour, day of the week, and season with times of peak-load varying by region. In hot climates, home air-conditioning usage increases the overall load needed in the late afternoon during the hottest part of the year. In cold climates, home heating increases loads in mid-mornings and mid-evenings during the coldest part of the year. Weather conditions are also important to grid operations since they affect system loads and extreme weather events can result in damage to infrastructure assets.

Parts of the electric grid are more than a century old, and 70 percent of the transmission lines and large power transformers are more than 25 years old [3], [4]. Along with aging infrastructure, the electric power system is evolving from one consisting of predominantly dispatchable generation sources (e.g., nuclear, coal, natural gas, and hydroelectric) to one having increasing percentages of variable generation sources (e.g., wind and solar). The deployment of variable generation varies widely across the U.S. as well as the ability of the regional grid infrastructure to accommodate them. Additionally, the centralized control paradigm where generation is dispatched to serve variable customer loads is being challenged with greater deployment of distributed energy resources (DERs). The increasing adoption of electric vehicles will also introduce load growth and potentially increased variability. These broad system changes have created a need for advanced solutions to help solve modern operational challenges.

Transmission Congestion

Transmission congestion occurs when changes in demand or generation result in power delivery that reach or exceed the physical capacity of the transmission network. Transmission constraint "refers either to [the limit placed on] a piece of equipment or an operational limit imposed to protect reliability that restricts these flows, or to a lack of adequate transmission capacity to deliver expected new sources of generation without violating reliability rules [1]." Power flows on transmission lines are limited for both electrical (e.g., voltage drop, phase, stability) and thermal (e.g., resistive heating, mechanical sag) reasons. Typically, these limits are calculated by system and planning engineers and applied by system operators to ensure safety and reliability. Transmission congestion results in generation commitment and dispatch decisions that vary from a lowest-cost basis, ultimately increasing the price of electricity.

In most organized wholesale markets, the locational marginal price of electricity (i.e., the price actually paid for electricity at different parts of the system) is calculated by adding the system marginal cost (i.e., the incremental cost of electricity to meet the last MWh of demand based on economic dispatch), the congestion component (i.e., the cost associated with the local dispatch of more expensive generation to relieve the constraint), and the marginal loss components (i.e., transmission losses associated with delivering the increment of electricity). While the settlement rules associated with these calculations vary slightly across the main wholesale markets, the result is the same: congestion costs are effectively paid for by the users of electricity.

Congestion costs can be quite substantial; between 2009 and 2017, California ratepayers' bills included $683.5 million in congestion-related costs [5]. According to a 2018 U.S. Department of Energy (DOE) report, the sum of real-time congestion cost for 2016 among major system operators—specifically, the California Independent System Operator (CAISO), the Electricity Reliability Council of Texas (ERCOT), Independent System Operator New England (ISO-NE), Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), and PJM—was $4.8 billion [6].

Traditional solutions to alleviating congestion include expanding, upgrading, or rebuilding the electric infrastructure. Transmission expansion projects in the U.S. totaled over $20 billion every year since 2014 through 2016 [7]. Since most transmission infrastructure was built between the 1960s and the 1980s, these investments are needed to ensure grid reliability as the assets age. One estimate projects that transmission replacement costs alone will increase by $1.2–3.2 billion per year over the next 10 years, assuming facilities need to be replaced after 60 to 80 years of operation [8]. Additionally, line reconductoring, which can be used in some situations to increase capacity on existing transmission right-of-way, can cost from $1 million to $8 million per mile depending on the voltage class of the line [9]. While these long-lead-time solutions may be needed in the long term, new and innovative technologies (e.g., DLR, demand response, power-flow controllers, DER, and energy storage) may provide congestion relief in the near term at lower expense.

Thermal Limits of Transmission Lines

A transmission line is referred to as being thermally limited when heating considerations set the maximum power flow capacity on the line. These thermal limits (i.e., maximum current carrying capacity at a given voltage) are determined based on the maximum operating temperature of the conductor that prevents premature aging and that limits conductor sag to maintain minimum clearances under the line for safety. Conductors expand at higher temperatures, lengthening the line and reducing the distance to the ground and other objects, which can result in arcing or faults if safe clearance distances are not maintained. Generally, the physical properties of the conductor (e.g., maximum temperature rating, electrical resistance, mechanical strength) and a set of environmental conditions (e.g., ambient air temperature, wind speed, solar radiation) are used to calculate thermal limits.

Static Line Ratings

Static line ratings (SLRs) are typically used by system operators in dispatch decisions to maintain safe operating conditions. SLRs are determined according to IEEE Standard 738, “Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors” [10]. These thermal ratings are usually calculated using conservative assumptions about the transmission-line operating environment such as static weather conditions, average wind speeds and direction, average ambient temperatures, and solar conditions for summer and winter seasons. While these assumptions are not worst case (e.g., based on absolute maximum ambient temperatures, zero wind speed, or full solar exposure), there can be instances where the real ratings based on actual conditions are lower than SLRs, putting the conductor at risk for thermal damage and greater sag. Overall, SLRs produce an inflexible constraint that does not take advantage of changing or favorable environmental conditions that allow for greater transmission usage in many hours of the year.

Dynamic Line Rating

DLR is a blanket term for the many different technologies and methodologies for determining conductor thermal ratings in a more-dynamic fashion using improved, more granular, or real-time data. In principle, DLR uses the same heat-balance equations as SLR, but includes the more-sophisticated time varying component, as shown in Figure 1. DLR can take various forms and includes dynamic thermal line ratings, ambient adjusted ratings (AARs), real-time thermal ratings, forecasted dynamic line ratings, and even analysis of existing lines with previously gathered data.

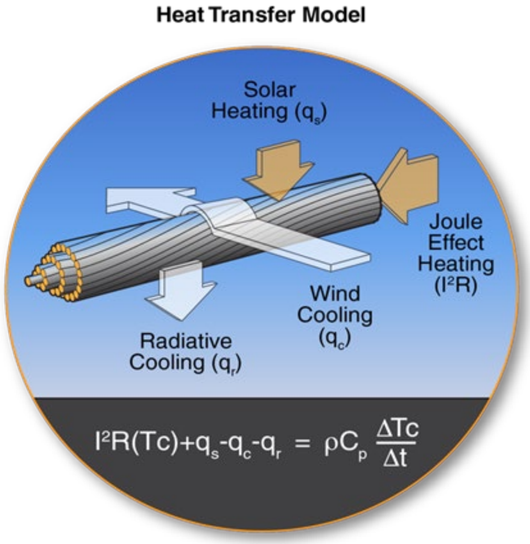

Figure 1: Heat-transfer model for a conductor.

DLR technologies have traditionally been bifurcated into weather-based and asset-based systems [11]. Weather-based systems focus on measurement of the environmental conditions that are direct variables in the heat-balance equations. Field data collected include wind speed and direction, ambient air temperature, solar radiation, and line current. Along with engineering design criteria, these parameters are used to calculate the maximum allowable conductor current. Asset-based systems focus on measurement of the conductor itself and include local conductor temperature, position or tension, and line current. These parameters are used to establish relational results that are combined with the physical specifications of the conductor to calculate the maximum allowable conductor current.

A comparison of the different systems and methodologies can be found in the "State of DLR Technology" section of this report; a more detailed assessment is provided in literature [12]. While there are advantages and disadvantages of each system, the key distinction is whether the system provides information on conditions and physical parameters of a single point along a line or can be representative of the entire length of the line.

Potential Benefits of Dynamic Line Rating

The objective of all DLR systems is to help system operators determine, accurately and reliably, the prevailing current carrying capacity limits of transmission lines to relax constraints based on thermal considerations [13]. In some cases, the consideration of seasonal or monthly ratings may help defer some infrastructure investments made for economic reasons or increase the utilization of existing lines. DLR also has the benefit of improving reliability and resilience by providing grid operators with enhanced situational awareness of individual assets, enabling greater flexibility. DLR can be applied in a variety of circumstances and voltage classes, but is particularly well suited to manage congestion on older lines, such as those at 115, 138, and 230 kV. While new lines may be designed to avoid a thermal limit, use of DLR can still be beneficial by providing situational awareness and supporting asset management.

Improved Congestion Management

In the generator-unit commitment process, grid operators decide ahead of time which generators to start up or shut down based on expected electricity demand and transmission constraints. To perform the day-ahead security-constrained unit commitment effectively, generator availability and transmission line capacity must be estimated. DLR technology, enabled with transmission capacity forecasting (TCF) based on weather forecasting, can be used to predict a transmission line's capacity hours or days ahead of time. By forecasting the expected transmission capacity more accurately, a more favorable commitment of generators in day-ahead markets and more efficient dispatch within real-time markets will be possible, thus reducing congestion costs.

The electric power system is becoming more dynamic with a need to make faster operational decisions based on more rapidly changing conditions. Real-time monitoring of the grid can support this need, especially as the mix of generation sources serving the country changes. For example, the growth in variable renewable generation, such as wind and solar, is introducing greater uncertainty and intermittency. The retirement of coal and nuclear plants and the addition of new natural gas plants are also changing power flows and reliability requirements for the system. When an unexpected event happens (e.g., an unplanned contingency, load- or wind-forecast error), transmission congestion can occur and grid operators may curtail generation [14]. DLR integrated into real-time operations can help better manage congestion and associated costs during these changes and events.

For example, ISO-NE realized significant consumer savings when it implemented AARs on transmission ties with New York during the 2018 “bomb cyclone.” At the time, much of the grid in the northeast was heavily congested due to high electricity demand and fuel supply constraints. ISO-NE issued an abnormal-conditions alert and increased their transmission line ratings to allow for greater capacity [15]. An ISO-NE report stated, “. . . the scheduling limit on the NY ties was increased from 1,400 to 1,600 MW. The increased limit was made possible by the cold conditions which helped to improve thermal transfer capability [16].”

It is widely accepted that implementation of DLR can provide congestion-management benefits. However, no comprehensive study has been conducted to assess the potential cost savings from widespread deployment of DLR in the U.S. across a variety of scenarios.

Increased Reliability and Resilience

Under NERC reliability rules, a power system must be operated so that it will remain stable despite the instantaneous loss of any single transmission line or generator (i.e., N-1 contingent). Grid operators and planners manage the system by ensuring there is enough spare capacity on other transmission lines and equipment so that a contingency will not overload those lines. In the event of overloads, relay settings may trigger protective actions that can lead to interruptions or outages. DLR can potentially improve reliability by calculating the true thermal limit for those lines and informing relay settings used to protect transmission equipment [9]. Furthermore, in cases where a customer’s supply might normally be disrupted to ensure system stability, the additional capacity from DLR can alleviate the situation and provide a means to avoid an outage, improving reliability metrics.

Another benefit of installing sensing and monitoring technologies like DLR is an increased situational awareness of the transmission system. Understanding when conditions may exceed constraints is critical in situations where lines may sag below clearances, making the system vulnerable to faults and safety hazards. Enhanced situational awareness can help ensure lines are not overloaded and, in effect, increase reliability metrics as well as protect the public from consequent issues of safety (e.g., fire or electric shock). Condition-based monitoring of transmission lines is also a possibility; rather than relying upon engineering assumptions and maintenance schedules, real-time status of the line can be used in decision making to mitigate component failures, boosting reliability.

FERC has stated that it understands resilience to mean “[t]he ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event [17].” Numerous power system events can cause disruptions, including component failure, human error, weather events, and damage—either unintentional or willful. Generally, methods, tools, and technologies that relax constraints on a system, give it more flexibility, or provide better situational awareness increase the resilience of the system. DLR can support more electric-delivery options during a disruption to mitigate load interruptions and facilitate recovery and restoration after an event.

Extreme events that cause electricity outages tend to have limited geographic scope; increasing transmission capacity to allow more power to be imported into a region from neighboring areas that are less affected by the event can increase grid resilience. DLR can be particularly beneficial during certain extreme weather conditions, such as the 2018 "bomb cyclone" and 2014 "polar vortex" events, where extremely low temperatures and wind chill caused high electricity demand and fuel prices, but also caused many generators to unexpectedly go offline due to equipment failures and fuel-supply constraints. DLR would allow grid operators to take advantage of the fact that colder temperatures and high winds in those events provided cooling that greatly increased the thermal limits of transmission lines.

In the recent FERC proceeding on power system resilience, all independent system operators explained the importance of transmission capacity for resilience. For example, the New York grid operator explained that "[m]aintaining and protecting existing interconnections between neighboring regions and continually assessing opportunities to improve interregional transaction coordination can bolster the resiliency of the grid throughout an interconnected region. These interconnections foster the opportunity for the Northeast and Mid-Atlantic markets to rely on a broader, more diverse set of resources to meet the overall needs of the region [18]."

III. State of DLR Technology

To operationalize DLR, several different technology components must be integrated into a system. The most fundamental is a means to measure the parameters that impact the transmission limits of a line. Obtaining these parameters can be accomplished through sensing and monitoring of either the conductor itself or environmental conditions. A communications channel must be established between the measurement apparatus and an analytics engine to transport data in a timely manner. The analytics engine, usually a software application, performs calculations or evaluations to translate measured parameters into information about the transmission line. Finally, the information from this process must be integrated into a control room or automated system where decisions are made.

Over the past several decades, a diverse set of technologies, methods, and systems have been developed to support DLR. Each system and method has advantages and disadvantages when it comes to accuracy, reliability, capital cost, ease of installation and integration, and maturity. Research efforts have focused on improving state-of-the-art technologies and addressing some of the barriers and limitations associated with implementing these different technologies and approaches.

Sensing and Monitoring

There are several ways to measure or determine the parameters that impact a transmission line. Table 1 lists some of the common sensors and methods used for DLR, including advantages and disadvantages. As mentioned earlier, the primary approaches are divided into monitoring either the conductor directly or the environmental parameters that affect line ratings. Direct conductor monitoring parameters, such as sag, tension, and clearance, are measurements used to calculate the conductor temperature. Generally, direct conductor monitoring approaches approximate the environmental conditions around the line, whereas environmental parameter monitoring approaches approximate the conductor conditions. The combination of measured and approximated parameters is used to dynamically rate the line.

Technology developers continue to seek the best combination of performance, cost, and ease of installation for sensing and monitoring approaches. Direct conductor monitoring tend to offer great accuracy and precision, but are challenged with installation and maintenance costs associated with adequately covering all spans or segments of a line. Some of the line-mounted sensor options may even require line outages, which impose additional costs. On the other hand, environmental parameter monitoring may be more cost-effective but are limited in accuracy by the location of weather stations and can face validation challenges. Both categories of approaches can be used in combination to complement one another in other solutions. While these various technologies and approaches have been verified in practice, the electric industry has not standardized or converged on the most accurate, efficient, or cost-effective methods for determining parameters.

Table 1: Common sensing and monitoring approaches for DLR.

	Measurement Parameter	Approach	Description with Advantages (+) and Disadvantages (-)
Direct Conductor Monitoring	Temperature	Ground-based Sensor	Devices like infrared thermometers/cameras are used to measure conductor temperature from the ground. + Temperature can be measured directly. + No line outage is required. - Difficult to verify and validate calibration. - Susceptible to physical interference, which may cause inaccurate readings.
		Line-mounted Sensor	Thermocouples or thermistors are affixed onto the conductor to measure its temperature. + Temperature can be measured directly. - Single point of measurement. - May require line outage during installation or maintenance. - Difficult to verify and validate calibration.
	Tension Monitor		Devices are attached to the conductor to measures the mechanical force between the line and the structure. + Monitors physical characteristics of a conductor and can benefit asset management (e.g., ice loading). - Requires line outage to install.

	Measurement Parameter	Approach	Description with Advantages (+) and Disadvantages (-)
	Sag	Ground- or Structure-based Sensor	Cameras monitor the distance a line has sagged. This is accomplished through image processing techniques, or with a target affixed to the line that the camera tracks. + No line outage is required. + Monitors physical characteristics of a conductor and can benefit asset management. - Difficult to verify and validate calibration.
		Line-mounted Sensor	Devices that measure the inclination and vibration of a line to determine the amount the line has sagged. + Monitors physical characteristics of a conductor and can benefit asset management. - May require line outage. - Difficult to verify and validate calibration.
	Clearance	Ground-based Sensor	Devices measure the electric fields emitted from a line to determine its distance above ground. + No line outage is required. - Susceptible to electromagnetic interference.
		Line-mounted Sensor	Devices mounted to the conductor that use sonar, light detection and ranging, or a range finder to measure its distance to the ground. + Monitors physical characteristics of a conductor and can benefit asset management. - Requires line outage to install. - Twisting lines can rotate the device, causing incorrect readings.
Environmental Parameter Monitoring	Weather	Numerical and Statistical Methods	Given historical weather data and other data sources, predicts weather conditions through computation and mathematics. + Minimal to no specialized hardware required. - Real-time predictions are error prone.
		Direct-Measured	Weather-station sensors measure wind speed, wind direction, temperature, and solar radiation. + Environmental parameters can be directly measured. - Many weather stations required to monitor large area.
		Physics Model with Direct-Measured	A computational fluid dynamics model uses analysis of the terrain to map wind speed and direction from weather stations data to adjacent areas. + A single weather station can effectively monitor a much larger area. - Models take additional time to run.

	Measurement Parameter	Approach	Description with Advantages (+) and Disadvantages (-)
			- Requires large amount of geographic data.
	Conductor Replica		Device uses a conductor material, placed close to and in the direction of the line to be monitored, as a proxy for the line. The material's temperature is measured while it is heated electrically to determine the ambient cooling conditions. + Does not require a line outage. - Difficult to verify and validate calibration.

Communications

Successful implementation of DLR requires the ability to communicate between the sensing and monitoring technologies and the control rooms or other decision systems in a timely manner. Many different technologies—radio, cellular networks, satellite, fiber optics, and even physical media—can be used as communication channels. However, the choice of technology will depend on the monitoring approach as well as requirements of the application, especially when it comes to data-transfer amounts and acceptable latency. For example, simple weather stations only need to transmit a few environmental parameters to the control center. For these small data packet applications, many existing technologies can be used, and the choice becomes dependent on cost, terrain, and network availability. As the number of capabilities and measured parameters increase for sensing and monitoring technologies, the communications requirement will also increase.

As utilities and system operators begin to rely on DLR systems for control, dispatch, and market decisions, the communications channel becomes a critical asset and will need to meet NERC's Critical Infrastructure Protection standards and requirements to ensure the authenticity and integrity of DLR data. Corruption of this data from any cause, unintentional or deliberate, becomes an operational problem that can have significant consequences. DLR system owners or service providers need to concern themselves with the reliability of the communication systems, including the cybersecurity of the sensing and monitoring technologies, the communication channels, and the operating systems. Cybersecurity breaches can manifest as data disruptions or poor data integrity that seek to invoke bad decisions or manipulate markets. System operators will need strategies and solutions for detecting and mitigating problems in communications.

Analytics Engine

The measured and approximated environmental and conductor parameters must be processed in order to become useful information. In most cases, the raw sensing and monitoring data is equated to the parameters measured without filtering or preprocessing to address potential errors. The measured conditions are analyzed according to IEEE Standard 738 or CIGRE Technical Brochure 2.12 to determine the steady-state or transient line current-carrying capacity [19]. The information resulting from these calculations can then be integrated into a control room, usually through a software interface, or studied independently to improve decision making.

Advances in models, methods, algorithms, and computational speed can change what is possible. For example, forecasting DLRs from measured data can provide additional value over what can be achieved with real-time information alone. Combining weather-forecasting methodologies and analytics with DLR technology is still in its infancy. Several national weather forecast models with high resolution could be used for this approach. An example forecast from the National Oceanic and Atmospheric Administration with their high-resolution rapid-refresh model is shown in Figure 2. This forecast gives wind speed and direction at 3 km spatial resolution for heights that roughly correspond to those of overhead transmission lines.

As with any modeling and analysis process, confidence in the data input and the validity of the processed output is critical. For example, wind speed and direction sensors can malfunction due to age or weather conditions and provide incorrect readings. A means to detect such anomalies in real time during the analysis would provide more confidence in decisions made based on these sensors. Models utilized in the analytics may also have accuracy sensitivities depending on the input range, requiring validation of models and the sensor data employed. Methodologies for providing diagnostics and forensics when system components degrade or fail are currently lacking from vendors. Similarly, assumptions made in developing models are often not validated. Remedying these shortfalls could be key to greater trust of DLR technologies in the long term.

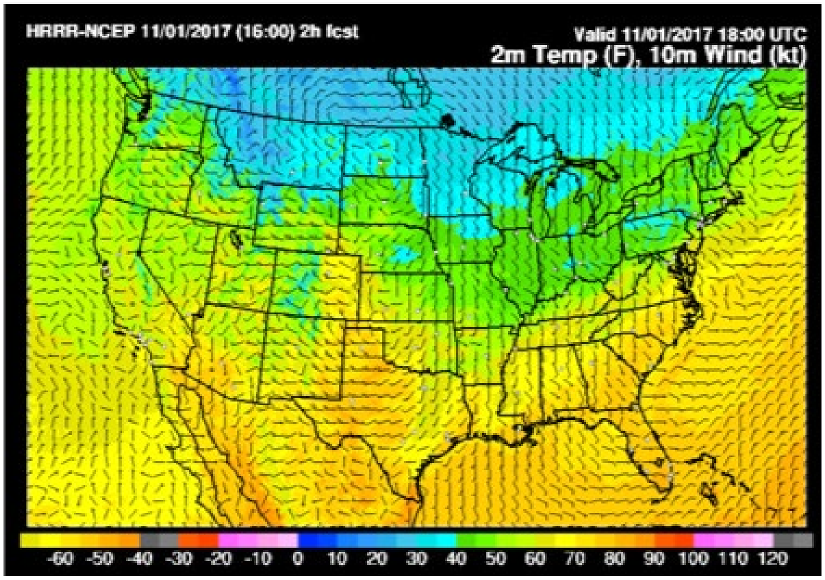

Figure 2: Example National Oceanic and Atmospheric Administration wind and temperature forecast (http://rapidrefresh.noaa.gov).

Integration

Integration into the control room is the most challenging step in implementing DLR because "[t]he work in a control room is highly complex [20]." Adding more information to the control room may excessively tax operators. In theory, calculated information from the analytic engine could first be read by the supervisory control and data acquisition (SCADA) system and then be displayed to operators. The display methodology (e.g., visualization, human-machine interface) most useful for system operators has yet to be agreed upon. Many control rooms have created displays for their own use, such as the one developed by the Spanish utility Red Eléctrica de España [21].

Making information actionable to the system operators is a primary concern; operators want a maximized but stable line rating that ensures conductor temperatures do not rise to the point where excessive sagging occurs. Depending on the implementation, DLRs can be noisy due to their dependence on wind speed and direction that changes rapidly. Filtering steps to reduce the volatility of information seen by an operator and methods to increase confidence in the ratings can be performed as shown in Figure 3. The bright blue line shows DLRs in 30-minute intervals with a 30 percent cap above the SLR, providing usability and ensuring safety, whereas the light blue line shows the real-time, unfiltered DLRs. The orange and dark blue lines show intermediate filtering steps. This is one example of how DLR data can be made more actionable; DOE has also funded research on alternative ways to more effectively present DLR data to system operators [20]. Overall, standardization of DLR data use and a baseline of expected functionality and performance will be needed to facilitate control room integration.

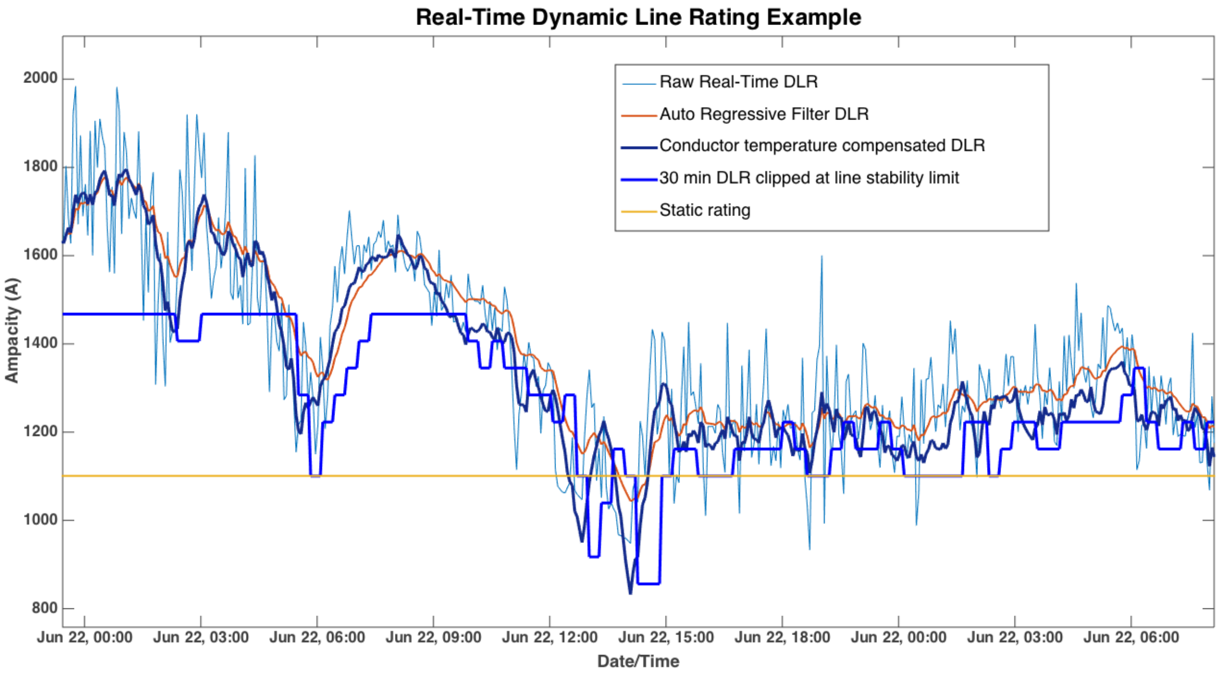

Figure 3: Example DLR calculation with raw real-time, auto-regressive average, conductor temperature compensated, and a 30-minute capped rating compared to static rating.

Barriers and Limitations

Despite DLR's potential for realizing cost savings and its ability to increase grid reliability and resilience, several barriers and limitations prevent widespread adoption. In general, hesitation exists in the largely risk-averse utility industry related to the use of unfamiliar technologies. One common concern is the accuracy and reliability of DLR data and related lack of operational knowledge and experience with the technology. Capital costs and installation complexities are a barrier as well. Another important variable that explains lower deployment in the U.S. relative to other countries is the different regulatory environments; the U.S. provides transmission owners little incentive to deliver more power over existing lines.

Accuracy and Reliability

The accuracy and reliability of DLR is critical to successful deployment and realization of cost savings, but inaccuracies can arise through both measurement and modeling errors [22]. Measurement errors include imprecise or inconsistent measurements and improperly calibrated direct-measurement sensors. DLR systems can also malfunction, in whole or in part, such as during a loss of communications connectivity. Additionally, some direct-measurement sensors are not able to measure transmission line parameters accurately during periods of light loading [23]. In these situations, there is always the option to revert to SLRs if the system is aware of the malfunction.

Modeling errors encompass inaccurate mathematical rating models, weather forecasting errors, and errors in collecting circuit topological and conductor data. For example, with older power lines, the thermal and mechanical properties of the conductor may have shifted over time due to aging and past use, yielding inaccurate results in clearance calculations. Similarly, CIGRE has documented that emissivity of overhead transmission lines can also change as lines age, affecting solar radiation impact and thermal-radiative properties [24]. Proper characterization of the transmission line itself should be made prior to implementing DLR.

These various sources of error reduce confidence in the capability of DLR to perform accurately and reliably. Developing methodologies and solutions to address these concerns will be critical to broader DLR adoption. Some strategies currently under investigation have employed a mathematically described confidence level within the DLR calculation, which rates the power line more conservatively proportional to lower confidence parameters such as weather predictions [25].

Operational Knowledge and Experience

As mentioned earlier, integrating DLR into control rooms requires accommodation. In a New York Power Authority (NYPA) DLR demonstration, the learning curve and trust in measurement accuracy were identified as challenges that might cause system operators to avoid adopting DLR [13]. In addition to the learning curve, introducing DLR systems would require the integration of a new terminal and additional training for employees. More importantly, a dedicated effort to ensure the system is providing accurate real-time information is required. Transmission operator feedback also suggest that they have limited time to make complex decisions and need intuitive information, especially in emergency situations [20].

Despite these challenges, studies conducted by NYPA and Oncor are optimistic about DLR implementation and offer remedies for control room integration issues: “One option is that a team of devoted engineers would oversee the DLR software and server, another option is to outsource the software to a third party, and a third approach is to integrate the DLR system directly into system operations [13]. ” The third approach, while comparatively more difficult, is the most cohesive. One way to make this transition as seamless as possible, according to the Idaho National Laboratory, would be to “integrate the DLR calculation in the operation system behind the scenes and replace the original static line limit information with … [the new] DLR information [20].” This approach would limit the information introduced on a system operator’s display and would not increase an operator’s mental workload.

DLR also imposes a variety of risks in its implementation. For example, if a transmission line is scheduled to operate above its static rating due to a forecast of strong winds (i.e., TCF), but a change in weather causes a sudden drop in wind speeds in real-time, the line would then be operating above its actual thermal limit. In this situation, there is an increased risk of clearance-height violations or, in extreme cases, heating to the point that the material and mechanical properties of the transmission line are degraded permanently. System operators will likely need to back up this method with shorter-term forecasting and real-time weather reporting to make operational decisions that protect assets and ensure safety. In general, changes in line ratings would be additional variables that would have to be incorporated into real-time dispatch decisions.

The use of enhanced ratings must also consider characterizing lines that run through vegetated areas to ensure proper clearance above or around vegetation, in addition to ground clearances. Vegetation near transmission lines pose a higher potential for wildfire risk, especially in drought-ridden areas [26]. Net benefits from employing DLR could quickly be lost if conductors become overheated or damaged due to incorrect sensor placement, inaccurate weather predictions, or unforeseen circumstances, leading to premature degradation and replacement, or other hidden costs.

Cost of Implementation

While relatively inexpensive compared to other transmission-capacity expansion and utilization options, cost of DLR systems and their implementation are not insignificant. Identifying the transmission line on which to install DLR and the specific technology to install can also prove difficult. The current carrying capacity of a particular line or line segment is often restricted by variations in wind cooling along the conductor [27]. For DLR to accurately and effectively maximize a transmission line’s thermal rating, the length of the line being monitored needs to be considered. Analysis is needed to determine the number of devices required and the relevant locations that give a reliable and accurate rating for the entire line. Identifying these “critical spans” is not trivial and will impact the cost of implementing DLR.

In a 2017 study by American Electric Power (AEP), a hypothetical DLR deployment on three sections of the 22-mile Cook-Olive 345 kV transmission line in the AEP transmission zone of PJM was simulated. With commercially available DLR systems, installation and implementation would have cost approximately $500,000 and generated a net congestion savings of more than $4 million in the year-long study [28]. This result would indicate a payback period of two months. As a point of comparison, if that line were economically upgraded, the cost would be \$22-\$176 million based on a Pacific Gas & Electric cost-per-mile estimate [9].

Overall, there is an absence of studies analyzing the payback period for DLR under the current technical landscape and power-system conditions. Improved studies are needed to better quantify and understand the financial impacts (e.g., costs and benefits) of DLR, especially for utilities and transmission owners, to overcome conservative assumptions that can impede implementation.

Monetization of Benefits

While DLR can lead to cost savings, these savings may not accrue to the financial benefit of transmission owners in the U.S. to sufficiently incentivize them to deploy such systems and other advanced transmission technologies (e.g., power flow controllers). This is due, in part, to the financial regulatory structure for rate-regulated utilities. Transmission owners generally can recover their prudently incurred expenditures for transmission under FERC's rules. However, under the current U.S. regulatory cost-of-service model, transmission owners receive a return on invested capital rather than a premium for delivering more power over existing lines or reducing transmission congestion. In addition, DLR involve many costs that are classified as operational and maintenance expenses that are ineligible for inclusion in calculating the return on equity (ROE), unlike physical assets. Thus, there may be a financial incentive for utilities to deploy new transmission lines and other large facilities rather than DLR to manage congestion.

While some FERC incentives are available for optimization of existing transmission facilities, to date, few, if any transmission developers or operators, have sought such incentives. FERC has recognized this issue in the past, noting in a 2012 policy statement providing guidance on its transmission incentives that, "the Commission is concerned that its current practice of granting incentive ROE and risk-reducing incentives may not be effectively encouraging the deployment of new technologies or the employment of practices that provide demonstrated benefits to consumers. Accordingly, the Commission remains open to alternative incentive proposals aimed at supporting projects that achieve these ends [29]." By contrast, other countries, such as the United Kingdom, have provided more direct and more comprehensive incentives for transmission line optimization, which may have led to greater deployment of advanced transmission technologies.

Additionally, many utilities may not be ready to address the challenges of incorporating DLR into their control rooms. Instead, they opt to use SLRs, focusing on system safety, reliability, and simplicity rather than the economic interest of consumers. This reflects the fact that economic benefits of enhancements to existing transmission systems generally accrue to the consumer, rather than the utility or transmission owner, and so become a secondary consideration. As a group of researchers noted, "In the case of transmission congestion, higher-cost generation is dispatched to meet load demand. Consequently, energy customers may experience an increase in electricity prices in the form of congestion charges. Therefore, the owner of the constrained transmission line is not directly affected by such circumstances and thus is not willing to remove the constraint [27].”

The interconnected nature of the electric grid also contributes to difficulty monetizing benefits. For shorter transmission lines (i.e., typically up to 100 km), the maximum current carrying capacity (i.e., loadability) is predominantly set by thermal limits while the maximum current carrying capacity for longer transmission lines is usually set by voltage limits and stability constraints [27]. Thermal limits tend to be higher than voltage or stability limits on longer lines, as shown in Figure 4, limiting the applicability of DLR. Additionally, implementation of DLR can move power flows to other lines, possibly voltage-limited lines or those owned by others, adding complexity in how costs and benefits should be allocated.

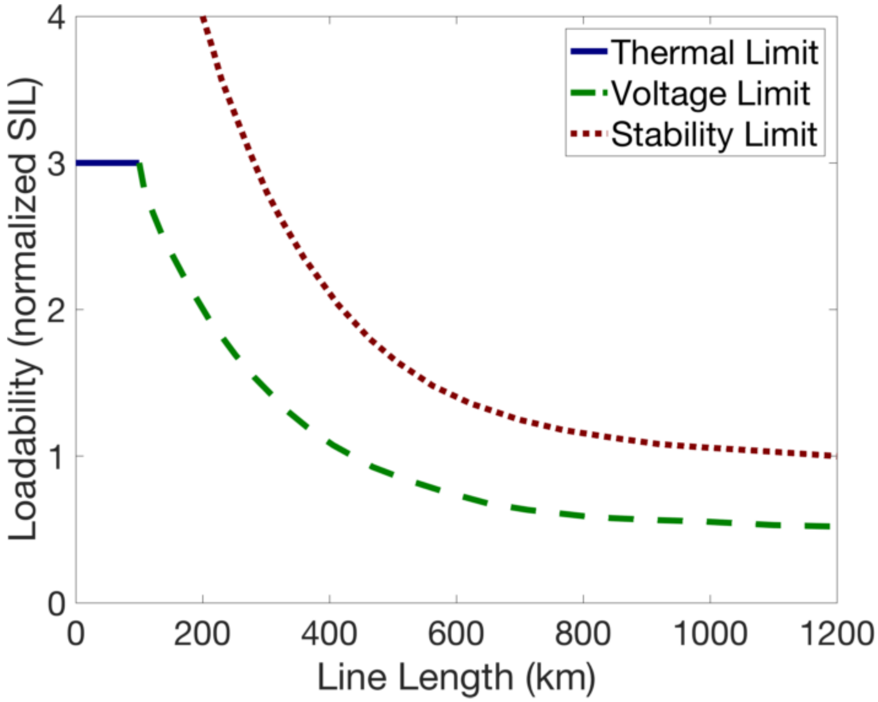

Figure 4: Power-transfer limits in relation to transmission line length, with loadability calculated per unit of surge impedance load (SIL)

IV. Stakeholder Views and Systems Impacts

The main benefit of DLR is the cost savings associated with utilizing existing equipment to carry more power, allowing greater utilization of low-cost generating resources while offering a potential low-cost alternative to spending millions of dollars on economic transmission upgrades. Increased situational awareness and better data collection would also greatly benefit a grid operator during regular operations or post-failure studies by providing more-relevant data for decision making or analysis. Due to these benefits, DLR has been deployed and studied domestically as well as internationally. However, the electric power system has numerous stakeholders, ranging from regulatory commissions to consumer advocates, industrial users to equipment vendors to independent power producers, in addition to utilities. Understanding their perspectives on DLR is important to broader adoption. Additionally, there are other system impacts that need to be considered in order to mitigate unintended consequences.

Case Studies

DLR is a technology option that has been available for 20 years, but has yet to see wide-scale adoption. However, several prominent small-scale investigations of DLR have been performed and examples of commercial products that measure the effects of line heating have been tested. Table 2 lists these known case studies (i.e., analyses, pilot implementations, and installation of commercial products) along with a description of the experience. While these results are generally positive, outcomes are difficult to extrapolate beyond the targeted lines.

Table 2: DLR case studies.

Entity	Year	Experience
REE: Spain	1998	400 kV transmission lines around Madrid were instrumented and the data stream was incorporated into the control room. DLRs showed promising headroom for increased line capacities [21].
Northern Ireland Electricity	2009	DLR was explored to address congestion from wind farm expansions. A 110 kV line was instrumented and studied, showing that line ratings could be increased by 10% to 20% in most remote locations, and by 26% in some cases [30].
RTE: France	2011	A sag sensor was tested on several 400 kV lines in France and found to be accurate enough to be used in ampacity calculations. However, they felt more research is needed to properly integrate the new data into control rooms [31].
Kepco	2013	The South Korean utility analyzed DLR for several transmission lines to address concerns with outage rates on parts of their system. DLR was found to allow maximum loading to increase by 35% over current values safely [32].
NYPA	2013	The demonstration project evaluated a variety of DLR systems and technologies, and how they could be used in transmission system engineering, operations, and planning. They found a positive correlation between increased real-time capacity and increased wind generation, and capacity increases of 30 to 44% over static ratings [13].
Oncor	2013	The demonstration project focused on monitoring an entire transmission line and included DLR integration into control systems. They observed capacity increases between 6 and 14% over AARs, available over 83% of the time. Additionally, they determined their DLR system could increase line capacity, on average, between 30 and 70% relative to static ratings [13].

TERNA: Italy	2013	The Italian transmission operator began implementing DLR on limited lines that were determined to be critical with the future objective to use data as input into optimal power dispatch. DLR has been used as a stop-gap measure to serve load prior to other network upgrades [33].
Idaho Power	2013-2018	Weather-based DLR provided increased situational awareness for more than 450 miles of transmission lines in highly complex terrain. Contingency relief has been realized multiple times as DLR forecasts are researched and validated [34], [35], [36].
AltaLink	2015	Conducted an analysis for a wind plant installation in Canada and found concurrent cooling avoided the need for system upgrades, saving the wind developer an estimated two million dollars. Further analysis showed an average 22% capacity increase over static ratings 76% of the time [37].
World Bank: Vietnam	2016	In its smart grid roadmap for Vietnam, DLR was identified as a tool to improve operational efficiency and to alleviate concerns on lines that are experiencing rapid load growth [38].
AEP	2017	Conducted a study of DLR applied to a 345-kV line across three spans. The results found significant capacity increases on the targeted line with the potential of $4M in savings [28].

Stakeholder Views

Numerous stakeholders would be affected or have an interest in the impacts of wide-scale implementation of DLR. Among them are Federal, State, Tribal, and local regulators; generation and transmission owners and operators; financial institutions and energy traders; technology vendors; and consumers. Various workshops, meetings, and fora have been organized to discuss the potential of DLR. Several comments from power systems stakeholders representing the breadth of views, insights, and experiences are presented below.

In a presentation to the MISO Market Subcommittee, Entergy explained their reasoning for implementing DLR on certain congested facilities:

> *By trending historical weather within Entergy's footprint, Entergy has found that rating adjustments based upon ambient temperature deviations from peak periods provide the most efficient gains and are most predictable on a forward-looking basis* [39].

At a FERC workshop held on June 13, 2017, EDF Renewable Energy, Inc., EDP Renewables North America, LLC, and E.ON Climate & Renewables, LLC, (collectively the "Generator Group") offered comments to elaborate on the Target Market Efficiency Project proposal. The group, concerned with unaddressed congestion at particular locations on the MISO-PJM seam, cited DLR as a possible means of addressing congestion issues and reducing costs to ratepayers:

> *Dynamic line ratings . . . can monitor variables such as temperature and wind speed in real time, and thus allow for greater throughput and use on an existing transmission line than use of static NERC-based limit* [40].

In response to a 2011 FERC inquiry on promoting transmission investment via pricing reform, Wisconsin Electric Power Company noted in comments that while they do support new grid construction as a means to reduce congestion, DLR can be implemented to more efficiently utilize existing infrastructure:

> *The ability to set ratings based on near-term predicted or actual conditions could allow a significant increase of transfer capability. Much of the congestion costs are realized during non-peak periods. Therefore, production cost savings can be achieved by calculating transmission ratings based on more representative conditions* [41].

In addition, Wisconsin Electric Power Company called upon the FERC to offer incentives for regional transmission organizations (RTOs) to implement DLR:

> *As an incentive to implement dynamic ratings, transmission owners could receive a higher ROE on assets utilizing dynamic ratings. In order to most effectively use dynamic ratings, RTOs would need to modify their systems. For this reason, the Commission should consider an appropriate incentive for the participating RTO.*

System operators play a critical role in DLR technology adoption. In its 2018 Reliability Needs Assessment Report, NYISO stated that, in order to meet future reliability needs and address transmission constraints, they are able to introduce changes in operating protocol, which can include implementing DLR for particular facilities [42].

In response to a 2018 MISO market-roadmap survey on priorities, various stakeholders stated their positions regarding the potential implementation of DLR. This document is unique in that an independent system operator (ISO) specifically requested and published information from participants in its system, something other ISOs have not shared publicly [43]. Pertinent responses are shown in Table 3.

Table 3: Stakeholder responses to MISO market-roadmap survey on potential implementation of DLR technology.

Survey Respondent	Response
DC Energy Member; Power Marketers/Brokers	"Pursue if MISO will be providing transparency on what ratings are used."
Detroit Edison (DTE) Energy Member; municipals/cooperatives/ transmission and distribution utilities (TDUs)	"DTE believes this project will help leverage existing line capabilities reducing the potential overbuild of transmission and resulting cost impact to our customers."

Survey Respondent	Response
E.ON Climate and Renewables North America, LLC Member; Independent Power Producers and Exempt Wholesale Generators	"In addition to dynamic ratings there is a recent development of devices that can dynamically change the impedance of a line (an example would be SmartWire's products), changing the flows in the system. We understand the integration of such devices would be a separate initiative, but we would ask MISO to consider other type of dynamic system topology changes if this initiative is implemented."
Louisiana Public Service Commission Non-Member with Voting Rights; State Regulatory Authorities	"… Congestion savings could be significant with utilization of Dynamic & Predictive Ratings. Wind generation is driving a lot of congestion in certain areas of the MISO footprint including the MISO-[Southwest Power Pool] seam. Quite a bit of the wind generation is off-peak during the winter and shoulder months. There is quite a bit of additional transmission capacity available when wind production is high as temperatures are generally lower along with increased wind speeds. It should be noted that Entergy incorporates these Dynamic and Predictive ratings and these increased ratings were utilized during the January MAXGenAlert."
Wind on the Wires (WOW) (now **Clean Grid Alliance**) Non-Member with Voting Rights; Environmental/Other	"WOW believes there is an important opportunity to make more efficient use of the transmission system with Dynamic Line Ratings, taking into account wind speed and ambient temperature. DLR should be used under normal operating conditions and not reserved only for emergency situations."
Wisconsin Public Power, Inc. Energy Member; municipals/cooperatives/TDUs	"While very supportive of efficient use of transmission, progress won't be made on this Market Roadmap candidate until transmission owners are supportive."

FERC has discussed the deployment of DLR technology in a policy statement and FERC orders. For example, in its 2012 policy statement on transmission incentives, FERC noted that transmission projects including DLR might constitute a new technology that facilitates more efficient and reliable usage and operation of existing or new facilities that would be eligible for consideration for a risks and challenges ROE-adder transmission incentive [29]. Additionally, DLR costs may be eligible for special transmission ratemaking processes, if requested [44]. FERC has also discussed how to treat advanced technologies during planning of transmission options [45] and contemplated that reliability standards might reflect DLR implementation [46]. Further, FERC directed NERC to consider DLR in future standards revisions, calling DLR an "innovative application [47]." Many of these policies were recently discussed in a FERC staff presentation at an Idaho National Laboratories workshop on DLR [48].

Impact on Different Generation Technologies

All utility-scale generation (e.g., nuclear, coal, natural gas, hydro, wind, and solar) requires a robust and reliable transmission system to deliver electricity to customers. Under the Federal Power Act (16 U.S.C. § 791a, *et seq.*), the transmission system is both open-access and technology neutral, meaning that no one generation source has priority over any other source for the use of available transmission capacity. Deployment of smart technologies, such as DLR, that reduce constraints and increase transmission capacity would not change this mandate. While distributed generation technologies are often connected to the distribution system and are less dependent on the transmission system, their deployment can be impacted by transmission constraints because increased variability at the local level requires power inflows and outflows from the bulk power system in order to maintain system balance.

Wholesale electricity markets play an important role in guiding the operating, planning, and investment decisions of owners and developers of generation technologies. In general, advanced technologies that reduce transmission constraints will produce a freer and more-open market. Generators with a lower marginal cost of producing electricity, such as variable renewable resources and natural gas turbines, will tend to benefit more from increases in transmission capacity. Consequently, implementation of DLR schemes may have an adverse effect on generator plants that depend on a constrained network for increased profitability. Overall, it is not possible to generalize the effects of DLR on specific generation technologies or sources because power flows are different across regions and change over time, and a variety of ambient conditions can affect line capacity.

While the impact of DLR schemes on different generation technologies cannot be generalized, there are instances in which specific sources can be advantaged. Interconnecting a new generator includes costs associated with upgrading the transmission network. DLR systems could be used to reduce upgrade cost, and potentially alleviate issues with nearby lines that are influenced by the new source to expand the number of viable locations for the plant. In other cases, wind turbines can occasionally deliver more power under DLR schemes due to the concurrent cooling of nearby transmission lines during periods when wind turbines tend to generate power. However, solar farms may experience the opposite effect where increased solar radiation heats the nearby transmission lines, reducing capacity when electricity production is high.

Ultimately, the implementation of DLR schemes would improve the overall economic efficiency of operating the electric power system. The resulting power flows and associated market impacts may drive certain generator plants out of business or change the viability of specific generation sources. The transmission system and wholesale electricity markets are fundamentally designed to optimize performance across multiple variables in the interest of serving the end-user. Market rules should not be influenced by any specific generation source or technology, but rather on the operating characteristics of generation sources and the impact of technology on overall power-system performance.

Other System Impacts and Considerations

Although it has been shown that DLR can provide cost savings [49] [25], concerns have been raised about the cost of installing and maintaining monitoring equipment [50], the challenges associated with maintaining equipment calibration, and the possibility of additional cyberattack surfaces. DLR can also improve system reliability through increased situational awareness and greater transmission capacity. However, by reducing the thermal headroom associated with SLRs, grid hardware components (e.g., power lines, transformers) will operate closer to their design limits, accelerating aging effects [51] and potentially driving the power system to a more-fragile state if these impacts are not adequately taken into account. Implementation of DLR must include principles of resilience to ensure that new hazards are not created. These additional considerations and issues will impact the business and operating models of utilities and other stakeholders.

Historically, utilities have operated their equipment conservatively, with significant headroom to handle unforeseen circumstances (e.g., contingencies, load surges). If maintenance is regularly performed, equipment that was designed for 40 years, at full loading, can last up to 60 years or more before they need to be replaced or rebuilt [52]. DLR schemes would enable utilities to safely subject their equipment to increased power flows, which raises the concerns of how this practice would impact equipment lifespan and maintenance cycles [53]. The additional electrical and thermal stresses will vary depending on location and circuit topology, possibly necessitating increased monitoring of the age and condition of grid assets in general. In some cases, the DLR system itself can provide this conditioning monitoring.

As DLR is implemented on a circuit, transmission owners and operators must focus on other critical elements to ensure the grid can handle the increased loading without issues. In addition to potential impacts on grid hardware components, protection systems may need to be examined. For example, relay settings may need to be updated to correspond to the increased capacities enabled by DLR. Regulatory limits on the upper bounds allowed for DLRs may be required to avoid these issues, as well as to address risks that can occur with sudden decreases in wind speeds. Power-system protection is an area that is getting more complex with adoption of new technologies, especially with significant growth of inverter-based generation.

Cybersecurity is a growing concern for the electric power industry; cyberattacks are continuously evolving and the number of attacks in the U.S. has been on the rise since the 2000s [54]. In general, adding new sensing and monitoring technologies, communications equipment, and computers to process data increases the cyberattack surfaces on the U.S. grid [55]. Implementing DLR is no exception; because most DLR technologies rely on wireless communications, they are vulnerable to denial of service attacks [56]. Efforts are needed to ensure DLR deployments are cyber secure. Additionally, system operators must have contingency plans to ensure safety and reliability, possibly reverting back to SLRs, should the DLR system fail or become compromised.

V. Conclusion

DLR, enabled by a diverse set of technologies, has the potential to reduce cost to American homes and businesses by alleviating congestion on transmission lines and improving safety and reliability through increased situational awareness. While beneficial, DLR systems are only one of many options for addressing grid congestion or increasing resilience; transmission expansion and other solutions (e.g., power-flow controllers, energy storage, DERs, and demand response) also play key roles in modernizing the grid. Experience with pilot studies and demonstrations have shown capacity increases, but the outcomes are difficult to extrapolate beyond the targeted lines. Additionally, numerous power grid stakeholders have expressed support for DLR, but technical, market, and regulatory challenges remain that must be addressed to facilitate broader adoption.

The U.S. currently lags behind other countries in the deployment of some advanced transmission technologies, such as DLR. One of the variables is a difference in regulatory environment and associated incentives. Broader adoption of DLR will also influence the performance of electricity markets, impacting the profitability or viability of specific generation sources. Further research is needed to better understand the economic benefits, costs, and impacts of wide-spread DLR adoption, especially at the regional or national level. Additional demonstrations and pilot studies can also provide utilities and other stakeholders with increased confidence in DLR methods and systems, reduce technology risk and uncertainty, and help ascertain the value of ancillary benefits such as improved situational awareness.

DLR deployments must be tempered with consideration for other system limitations and the potential for unintended consequences. As the capacity on instrumented transmission lines increase, other constraints in the transmission system can occur. Additionally, increased power flows on circuits will also impact aging of grid hardware components on that circuit and may present challenges with protection systems and settings. Other integration challenges such as interoperability and cybersecurity must also be addressed to maximize the potential of DLR without imposing new system risk. Establishing standards and best practices to alleviate these concerns would ultimately make DLR a more viable solution across the multi-stakeholder industry.

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