UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Inquiry Regarding the Commission's Transmission Electric Incentives Policy	**)** **)**	**PL19-3-000**

WATT COALITION INITIAL COMMENTS
June 26, 2019

Working for Advanced Transmission Technologies ("WATT Coalition") appreciates the opportunity to comment on the Federal Energy Regulatory Commission's ("Commission") March 21, 2019 Notice of Inquiry ("NOI") in the above-captioned proceeding. The WATT Coalition offers a modest, targeted incentive for the Commission to comply with its obligations under Section 219(b)3 of the Federal Power Act regarding efficient operations of the existing transmission network.

"The U.S. currently lags behind other countries in the deployment of some advanced transmission technologies, such as [Dynamic Line Rating]. One of the variables is a difference in regulatory environment and associated incentives."
--US Department of Energy, June 2019[1]

I. WATT Coalition

The WATT Coalition is an ad hoc coalition of companies who support greater deployment and use of grid operating technologies such as Dynamic Line Ratings, Power Flow Control, and Topology Optimization. WATT includes the following six members:

Ampacimon is a global leader in grid monitoring solutions that utilize patented sensors and software to increase the capacity of transmission and distribution assets. Their dynamic line rating systems have been deployed worldwide with grid monitoring sensors and software installed on over 50 transmission lines.

Lindsey Manufacturing Company provides innovative and cost saving products to the global electric utility industry. Lindsey is an industry leader in transmission line monitors and software for measuring and forecasting dynamic line capacity. Their emergency restoration structures enhance grid resiliency by quickly bypassing collapsed transmission towers, and their high accuracy distribution class current and voltage sensors for optimizing distribution networks.

[1] US DOE, Dynamic Line Rating, Report to Congress, June 2019, p. 23.

LineVision provides utility solutions that serve to increase the capacity, flexibility, and reliability of existing transmission lines. Their systems assist in transmission line monitoring, asset health monitoring, and the forecasted and real-time adjustment of transmission line capacity.

NewGrid is a software firm that provides transmission topology optimization for the electric power industry. NewGrid's software automatically identifies grid reconfigurations to route power flow around congested transmission facilities (it is, in a sense, a "Waze" for the grid).

Smart Wires delivers grid optimization solutions around the world that work to create a more flexible and efficient transmission grid. Their power flow control technology dynamically controls transmission line reactance to direct power onto lines with spare capacity.

WindSim has developed a wind farm design software based on computational fluid dynamics that optimizes wind turbine placement. Using accurate simulations, WindSim software can more realistically capture terrain effects on wind conditions than many traditional technologies.

Grid Strategies LLC serves as the convener of the WATT Coalition.

II. Policy Imperative

EPAct 2005 directed FERC to "encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities." [2] (FPA Section 219b3) That directive has never been implemented. The law also directed FERC to "encourage, as appropriate, the deployment of advanced transmission technologies."[3]

When the Commission implemented the rate incentives provisions of EPAct in Order No. 679, very little guidance was provided on the *operational* aspect of transmission relative to the incentives for grid *expansion*. In part that was because the relevant technologies were only beginning to emerge at that time and few commenters raised the issue in the docket. In 2011 after five years of experience with Order No. 679 the Commission observed, "To date, the vast majority of applications for transmission incentives filed with the Commission have focused on the enlargement of facilities, including construction of new transmission facilities. Few applications have focused on the improvement, maintenance, and operations of transmission facilities or on increasing their capacity or efficiency… For example, this could include software improvements that enhance scheduling and dispatch or investment in tools to enhance self-healing grid capabilities or improved situational awareness."[4]

In the subsequent policy statement the Commission once again acknowledged the issue but did not establish any implementing regulations: "Investments in the following types of transmission

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[2] 16 U.S.C. § 824s(b)(3).
[3] 42 U.S.C. § 16422.
[4] Promoting Transmission Investment Through Pricing Reform, Notice of Inquiry, May 2011, RM11-26, p.13.

projects may face the types of risks and challenges that may warrant an incentive ROE based on the project's risks and challenges that are not either already accounted for in the applicant's base ROE or could be addressed through risk-reducing incentives:… projects that apply new technologies to facilitate more efficient and reliable usage and operation of existing or new facilities…Examples of projects that meet this description include those that create additional incremental capacity without significant construction (e.g., through the use of dynamic line rating), that allow for more efficient balancing of variable energy resources, and/or that provide increased grid stability. In addition, the Commission is concerned that its current practice of granting incentive ROEs 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."[5] Thus, there continues to be no policy implementing Section 219(b)(3) of the FPA.

In addition, the operational efficiency of transmission hardware has not been a focus of Commission action in any of the various rulemakings outside of Order No. 679 either. It was not a focus of restructuring or competition-related orders such as Nos. 888, 2000, 717, 719, 697, 2006, 743, 775, 773, 841, 845, or 890.[6] The physical hardware has been generally viewed as a fixed asset common carrier on top of which energy and ancillary services markets operate. Yet for all the hundreds if not thousands of proceedings on energy market design, significant efficiencies lie untapped in the operation of the physical network hardware.

III. Untapped Efficiencies

As described in the attached affidavit in Appendix A of Dr. Richard Tabors, one of the creators of the Locational Marginal Pricing market design in use in today's RTO and ISO markets, when FERC and the industry restructured wholesale electricity markets, designers consciously made simplifying assumptions about the transmission system and its operations. They assumed the transmission grid was essentially "fixed" in capacity and configuration. At the time that was reasonable to do given the complexity in setting up large regional energy and ancillary services spot markets with separate prices at thousands of nodes on the system and the structuring of financial transmission rights. With the development of new technologies, that assumption ignores how today transmission physical assets can operationally be managed and controlled to improve power delivery. Now is a great time to take on that next step of identifying and encouraging the planning and operating efficiencies that have been untapped thus far. This Commission can lead that effort with a policy statement or rulemaking adopting the WATT Coalition or similar proposal to move forward in the shortest period of time with the greatest benefit for consumers.

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[5] Promoting Transmission Investment Through Pricing Reform, Policy Statement, November 2012, RM11-26, p.15.

[6] See https://www.ferc.gov/legal/maj-ord-reg.asp for major Commission orders.

IV. Issues with Current Regulations

There are both economic issues and process issues with current FERC-regulated incentives.

Misaligned incentives

The economic issues are that transmission owners do not have incentives to operate their assets more efficiently, i.e., to deliver more energy over their existing assets. Their returns are based on invested capital and allowed rates of return, not delivering more or better service. This is a common problem in regulated industries.[7] Whether or not regulation is labelled "incentive regulation" is immaterial; as the famous regulatory economist and regulator Alfred Kahn said, "all regulation is incentive regulation." Under the current regulatory regime, utilities profit more on large capital investments than on smaller ones that may achieve the same purpose.

Innovations are affected by this capital bias because they are generally not capital intensive. Some innovation activities are based on operations rather than capital assets. Under these circumstances, these operating costs are only recovered dollar for dollar and passed through in rates whereas traditional capital expenditures reward the Transmission Owner with a return on the investment. In addition, given current regulatory structures in the U.S. and unlike the system of Great Britain, the utilities do not profit if they reduce operational expenditures. These innovations may also not be attractive to Transmission Owners and operators because they require more management oversight since they are operational and may require new functions and organizational capabilities necessitating management attention – a valuable and limited resource. These factors result in a bias against expenditures that are focused more on operational change than on capital expenditures. In this regulatory structure, there is little, if any, upside for innovation in grid operations even if they can increase its cost-effectiveness and capabilities.

Process issues under FERC Order 679

The process issues are that advanced technology deployments are generally low cost and rapidly deployable, whereas both FERC incentives and RTO/ISO planning processes are structured around projects costing hundreds of millions to billions of dollars and take years to implement. It is impractical to have a full planning process or a FERC proceeding for a $50,000 project.[8] Existing FERC policy is applied to projects that typically cost 100 times more.[9] The FERC process also centers around grid expansion proposals and while new technologies are

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[7] The problem is called the "Averch-Johnson effect" from a 1962 article: Averch, Harvey; Johnson, Leland L. (1962). "Behavior of the Firm Under Regulatory Constraint". *American Economic Review*. **52** (5): 1052–1069. JSTOR 1812181.

[8] See advanced technology project list for an Australia transmission owner ranging in size from $50,000 to $4.9 million: https://www.aer.gov.au/system/files/AER%20-%20Final%20Decision%20TransGrid%20transmission%20determination%20-%20Attachment%2011%20-%20service%20target%20performance%20incentive%20scheme%20-%20April%202015%20fixed.pdf page 11-9 to 11-16 .

[9] See, e.g., https://www.ferc.gov/CalendarFiles/20180213173212-ER18-463-000.pdf

sometimes part of those applications, innovative technologies focused on grid operations are often more beneficial on existing (and often older) assets.

Another process issue that provides a disincentive to innovative technologies is that they often do not present any "risks and challenges." Dynamic Line Ratings, Power Flow Control, and Topology Optimization offer no risks to Transmission Operators and operations, yet they would need to be shown to be risky in order to qualify for incentives given current regulatory standard.

V. Advanced Technologies and their Benefits

The attached paper by Bruce Tsuchida of the Brattle Group and Rob Gramlich of Grid Strategies in Appendix D demonstrates that grid operations technologies are viable, provide benefits, and those benefits can be quantified for purposes of FERC incentives policy.

VI. WATT Coalition Incentive Proposal

We propose here a specific, well-defined incentive structure focused only on *small projects* that provide *quantifiable congestion reduction benefits*. While there are significant reliability and resilience benefits to these technologies, we leave those aside at this time in order to make incremental progress in areas where the benefits are relatively easy to quantify. This stand-alone incentive may be used along with other current or revised transmission incentives and other policies. We focus on small projects because we recognize the larger the project, the greater the cost allocation and consumer impact risks, even for beneficial investments. This incentive is based on the existing economic planning and operations planning processes which have been approved by FERC, are in transmission tariffs, and have well accepted quantitative models in place. The proposal draws lessons from other countries where different incentive structures have led to different outcomes. In particular, the regulatory structure of Great Britain provides "shared savings" based incentives for reducing congestion. Transmission owners there have responded by deploying advanced transmission technologies. In Australia there are incentives for implementation of advanced grid operations technologies which have also led to expansion of these technologies. Appendix C describes the Great Britain and Australia models.

The proposed program would work as described below. Illustrative quantitative examples are provided in Appendix B.

FERC would establish criteria for what qualifies as "transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities" per FPA Section 219(b)3. We suggest the following definition: "hardware, software and associated protocols applied to existing transmission facilities that increase the network's operational transfer capacity." This definition is technology-neutral. It would include DLR, Topology Optimization, and Power Flow Control, and likely others now or in the future.

The proposal operates in two time frames, advance planning, and operational planning.

Advance planning time frame

Within the regular economic planning process run by the Planning Authority (the entity that complies with Order No. 1000 planning requirements), Transmission Owners / utilities would submit projects that comply with both the regional criteria for economic projects and FERC's bright-line criteria and are under a certain total capital investment threshold.

We propose a cost limit, to limit risks on consumers. We suggest a cap of $25 million.

The Planning Authority (RTO or ISO where they exist) would then evaluate the proposed project based on the benefits and costs using standard costs and benefits calculations as determined by typical transmission benefit studies for the study timeframe taking both into consideration.

For the benefits assessment, studies would usually include production cost and capacity cost savings. These studies could be performed by TOs, the Planning Authority or other specialized third parties.

Projects should follow the already established Planning Authority approach for determining whether the economic project passes the criteria for approval.

If the project benefits exceed the costs on a net present value basis, the Planning Authority would endorse the project and the award of the shared savings incentive.

The incentive to the utility would be a share of the savings multiplied by the net savings. We propose a 25 percent share.

If the utility decides to proceed it would include the approved projects along with the shared savings amount transmission revenue requirements filed with FERC, including their Planning Authority's assessment.

Operations planning time frame (months, weeks, days, intra-day)

Each party (e.g., Transmission Owner (TO) or RTO) interested in participating in the Operations Incentive Program would propose to the FERC their own specific program to deploy and implement the technologies and other measures in operations planning. For programs proposed by RTOs, member TOs would have the option to participate in those programs, to propose their own specific programs to complement or substitute the RTO program, or take no action. The proposal would include:

- a quantification of the expected societal benefits of the program;
- a quantification of the expected costs of the program;
- rules specifying what the program will consist of, including the technologies or measures for deployment and use as part of the program;
- the proposed duration (e.g., 3 years); and
- the incentive the participating party will receive for conducting the program.

FERC would approve or reject the shared savings program; if approved, the participating party would decide whether to execute it.

In the execution phase, the participating party would evaluate opportunities to reduce congestion using solutions that are deployable within the operations timeframe. These evaluations are expected to be performed multiple times over the operational timeframe (e.g., 6 months before the start of a given season, 1 month before the start of the season, 1 week before real-time operations, 1 day before real-time operations, etc.) using the latest data available at that time (e.g. the most current outage schedule). During each evaluation, the participating party would identify a set of candidate projects and operational measures to reduce congestion. These projects and operational measures would then be assessed using pre-defined criteria. If a candidate project meets the criteria and sufficient program funding exists to implement the project, the party would execute the project (e.g., deploys dynamic line rating on a given line, implements a beneficial reconfiguration found with topology optimization software, deploys power flow controllers on a certain line). The set of candidate projects and operational measures will depend on the timing of the evaluation relative to real-time operations. For example, deploying mobile power flow controllers and dynamic line ratings are viable candidate projects up-to a month prior to real-time; making appropriate topology changes are viable up-to near real-time operations.

Periodically (e.g. annually), the actual benefits of the program will be compared to the expected benefits that were specified in the program application and this comparison will be reported to FERC In RTO areas, the report would be developed by the independent market monitor. If the actual benefits do not meet a threshold of performance, the participating party has the option to issue an action plan to correct this discrepancy (including adjusting the program based on updated knowledge, or even terminating the program if warranted).

At the end of the program period, the overall benefits will be compared to the expected benefits and the comparison reported to FERC. This report will be considered if the participating party choses to apply for future programs.

VII. Assessment of proposal

Any proposal must meet the goals of FPA 219(b)3 to "encourage deployment of transmission technologies … to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities." It must also support reliability, be just and reasonable, and be administratively workable.

Deploys technology

The program will likely increase deployment of transmission operations technologies because transmission owners would capture some of the benefits that accrue to consumers but currently do not affect the TO's bottom line.

Certainty for TO's is important to achieve deployment. The Commission's Question 6 asks, "How would a direct evaluation of expected benefits, instead of using risks and challenges as a proxy, impact certainty for project developers?" In this proposal, the TO would know up front the expected benefits and shared savings amount before it proceeds. Programs that measure congestion after the fact, or claw back incentives based on congestion outcomes, would not provide the needed certainty. Too many factors affect congestion, namely natural gas spot prices.

Supports reliability

This proposal preserves reliability since the TO will maintain responsibility for operations and be required to comply with all reliability standards. The Planning Authority/RTO will provide an independent check on the reliability of the program prior to implementation and may have a role in administering or providing reporting for some of these programs. Monitoring and control of transmission assets only provides more information and tools for operators.

Just and reasonable

The program would benefit customers because it is focused only on instances where net savings are quantitatively demonstrated. It would also contain costs by having RTO and FERC review of the benefits and costs and capping the eligible project costs.

Administratively workable

The program is administratively workable because only one filing is needed per TO or RTO, as appropriate, rather than a filing for every installation--that could be thousands of FERC filings. It does not create excessive administrative costs at the RTO level (e.g., doing a $50k study to evaluate a $50k project).

VIII. Incentive Criteria and Objectives

FERC currently uses a "risks and challenges" approach to incentives and posed questions in the NOI about shifting to a "benefits-based" (Questions 1-3 on risks and challenges; Questions 4-7 on benefits) or "characteristics" approach (Questions 12-16). We support moving away from a "risks and challenges" approach because it requires proponents to demonstrate riskiness, for projects or deployments that may not be risky at all.

Support for Benefits Approach

We support a change to a benefits-based approach, which would incent the deployment and use of efficiency-improving technologies to the benefit of end consumers. The WATT Coalition approach described above is focused on quantifiable benefits.

Characteristics

The Commission also posed questions about “characteristics” criteria (Questions 12-16). Question 18 reads: “As an alternative to a direct examination of expected benefits, the Commission could use transmission project characteristics as a proxy for expected benefits. These project characteristics could include…Such an approach could also consider granting incentives based upon inclusion of specific transmission technologies.”

The Commission may wish to use a criterion related to technology types or “innovation” in tandem with benefits. For example, if the Commission would like to limit the scope of what might be eligible under benefits alone, using the two together may help. That would allow incentives to be more narrowly tailored to activities such as the deployment of these grid operations technologies as required under FPA 219b3 that over time can become a standard part of transmission functions, but which need an incentive to get them off the ground.

IX. Conclusion

We urge the Commission to adopt this proposal because it will lead to more just and reasonable rates and allow the Commission to comply with Congress’ explicit direction in FPA Section 219(b)3.

Respectfully submitted,

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Appendix A: Statement of Dr. Richard Tabors

Looking back over the changes in the economics and engineering in the electric power sector in the US since the development of the original concepts contained in ***Spot Pricing of Electricity*** (1989) provides a continuing picture of progress during which locational marginal pricing (LMP) has become an integral component of wholesale power markets.

During this same period, utility-scale renewable technologies have taken giant steps forward. Cost per kilowatt hour has plummeted. And ever improving performance has made possible the integration of these technologies into the larger grid.

More recently, price-responsive demand management, a basic tenet of the original logic of ***Spot Pricing*** has been adopted slowly but, together with distributed energy resources (DER) located both in front of and behind the meter, is now also an integral part of the system.

Transmission is the component of power systems that has not experienced comparable economic and engineering progress in response to market forces. The introduction of non-discriminatory open access in the 1990s provided access to the wires and circuits on a common carrier basis, but failed to incentivize the owners and operators of the transmission grid to improve the efficiency of operations.

The reality through the period of restructuring of the 1990s was that attempting to move transmission into a competitive platform was either not truly necessary or was simply too difficult to implement.

Small steps were initiated. The Energy Policy Act of 2005 and the Federal Energy Regulatory Commission's Order No. 1000 endorsed introducing competitive market incentives in the build out of transmission. In theory, the creation of regional transmission organizations (RTO) or independent system operators (ISO) should have created a constituency for investment in improved operational performance of transmission systems. This has not, however, been the case in large part because cost-base ratemaking perpetuates the incentive of transmission owners to chase capital intensity at the expense of improved operational efficiency.

In retrospect, it is apparent that ignoring transmission while introducing market reforms to other components of power systems may have been expedient but has produced a transmission system that is operated as a fixed asset; fixed in space and time.

It is time to introduce long-overdue market-based incentives to encourage non-capital- intensive solutions to improve operational efficiencies in the transmission sector.

Richard D. Tabors, Ph.D.
President, Tabors Caramanis Rudkevich
And Executive Vice President, NewGrid
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Appendix B: WATT Coalition Incentive Proposal Illustrative Examples

Example 1: Planning time frame

- Utility submits proposal to Planning Authority economic planning process within their planning region to identify project. Utility funds the study.
- Cost $10M, as submitted by TO and verified by Planning Authority.
- Planning Authority modeled benefit is $30M benefit over normal 10-year planning period
- $30M-$10M = $20M net benefit
- Sharing ratio of 25%
- Share of savings = .25 * $20M = $5M
- Utility adds $5M share of net savings + $10M project cost = $15M into its annual FERC filing to increase its annual revenue requirement by that amount, along with the study and supporting documentation for public review.
- Utility undertakes project, pays the $10M cost
- Utility incentive/profit = $5M ($15M revenue - $10M cost)
- Utility commits to keep in place for at least ten years.

Example 2: Operational planning

- Utility files with FERC for program approval
- Program description indicates how technologies would be deployed and used in operations planning and real-time operations
- Cost benefit study filed with program proposal estimates that program costs would be $10M/year, program benefits would be $50M/year
- Utility gets approval to spend up to 2 x $10M annually in the program and pass through the actual costs to customers (2x to account for the fact that there could be significant variance in technology deployment needs year over year)
- Estimated net annual benefit is $50M-$10M = $40M
- Sharing ratio @ 25%
- Utility incentive = 25% * $40M = $10M. This is what it keeps in addition to program cost recovery.
- Utility puts the incentive amount ($10M) plus the cost (up to $20M) into formula rates annually.
- During the year the utility deploys advanced transmission technologies based on operations planning studies as specified by the program
- At year end, ex post benefits are calculated and reported (by Independent Market Monitor if utility is an RTO member).

Appendix C: Lessons from Great Britain and Australia Regulatory Models

In places where the incentives are different from the US cost-of-service method of transmission monopoly regulation, results have been different. Here we summarize the key elements of these regimes.

Great Britain RIIO Model

"RIIO," refers to Revenue = Incentives + Innovation + Output.[10] For transmission owners RIIO features an 8-year rate plan and an award-penalty mechanism that incentivizes utilities to identify opportunities to save their customers money. Additionally, consideration of multiple future scenarios and decisions to take forward investments that provide the most benefit regardless of which future scenario unfolds is a key component of system planning in the UK. The approach begins with Ofgem, the regulator, setting unit cost allowances (UCA) for boundaries across the UK network. UCAs are Ofgem's estimate for the investment per MW required to increase transfer across a boundary. In the next step, the system operator (SO), which functions similarly to US ISOs/RTOs, develops 4 scenarios for future energy needs and forecasts the transfer requirements across each boundary under each scenario. The Transmission Owners (TOs) propose investment options for a given boundary and those options are evaluated by the SO under a method called Least Worst Regrets. This method essentially results in investment recommendations for the option which provides the best benefit across all scenarios. The TO is only able to recover the UCA for a given boundary, so if the cost of the SO's recommended investment option exceeds the UCA, the TO takes a financial loss. However, if the cost of the recommended investment option is less than the UCA, the utility gets to keep half of the savings. This shared savings concept for reducing costly congestion could be useful in the US.

Notably, RIIO requires stronger and more extensive regulatory oversight, benchmarking and cost estimation than what is currently in place in the US. Great Britain also does not have the transmission-distribution split we have in the US, and many of the performance-based incentives are directed at end-user reliability and service. As such, many of the RIIO details may not be directly applicable.

Australia Technology Incentive

Australia has a Network Capability Incentive Parameter Action Plan ("NCIPAP") and "Service Target Performance Incentive Scheme" (STPIS) which can be a model. The approach has successfully deployed a number of new technology projects.[11] It has worked to deploy technologies on older existing lines and has worked for smaller as well as larger projects. The

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[10] https://www.ofgem.gov.uk/network-regulation-riio-model , https://www.ofgem.gov.uk/electricity/transmission-networks/network-price-controls , https://www.ofgem.gov.uk/ofgem-publications/64003/pricecontrolexplainedmarch13web.pdf

[11] https://www.aer.gov.au/system/files/D16-11901%20AER%20-%20Final%20decision%20-%20TransGrid%20transmission%20determination%20-%20May%202018%202.pdf Pp. 14-15

projects range in size from $50,000 to $4.9 million.[12] (Australia dollars are worth about 70 percent of US Dollars at the time of this filing). The total cost on consumers of the NCIPAP program has been limited--approximately $36 million worth of projects[13] for a utility that earns around $700 million per year in authorized revenue.[14]

The Australian approach begins with transmission owners who develop a package of technology applications for a defined planning period. Transmission owners are required to consult with the independent system operator which conducts independent analysis of network limitations, considering historical congestion, future network flows, and reliability and security implications, and prioritizes options based on reliability and economic value for customers. There are specific components of the overall incentive plan for different activities. The Network Capability Incentive Parameter Action Plan (NCIPAP) provides ROE incentives to the transmission owner for adopting advanced technology projects. Cost impacts on consumers are limited to 1 percent of the transmission owner's revenue requirement.[15] There is also a "Market Impact Component" in which the TO is rewarded/penalized for transmission facility outages that cause congestion. The utility earns a 50% higher Return on Equity than its base ROE on these investments.

Consumer impacts are limited by the cap on total expenditures, and the review by the independent RTO.

The grid operator and regulator approve a bundle of small projects together which improves its administrative workability.

The reliability and economic benefits are assessed by the independent and expert grid operator and reviewed by regulator in a public process. In one decision the regulator stated, "We considered [transmission owners] are best placed to identify limitations in their networks and implement low cost solutions to address those limitations for the benefit of consumers. However, we recognised that the existing regulatory framework did not incentivise this behaviour. The NCC is aimed to incentivise increased capability of existing assets in the network when needed most. It does this by requiring [transmission owners] to reveal the existing capability of their networks and to identify low cost projects to increase network capability that would provide greater value to generators and consumers. Generators benefit from improved capability because there is a lower risk of their generation dispatch being constrained, which is ultimately passed onto consumers through lower wholesale electricity prices. The [incentive policy] incentivises [transmission owners] to improve ability of their networks to meet peak

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[12] Ibid.

[13] https://www.aer.gov.au/system/files/AER%20-%20Final%20Decision%20TransGrid%20transmission%20determination%20-%20Attachment%2011%20-%20service%20target%20performance%20incentive%20scheme%20-%20April%202015%20fixed.pdf page 11-16.

[14] Revenue requirement page 10 https://www.aer.gov.au/system/files/D16-11901%20AER%20-%20Final%20decision%20-%20TransGrid%20transmission%20determination%20-%20May%202018%202.pdf

[15] See https://www.powerlink.com.au/sites/default/files/2018-02/Service%20Target%20Performance%20Incentive%20Scheme%20%28STPIS%29%20Overview.pdf

demand without additional major augmentation capital expenditure, which also translate to lower prices for consumers."[16]

[16] https://www.aer.gov.au/system/files/AER%20-%20Final%20Decision%20TransGrid%20transmission%20determination%20-%20Attachment%2011%20-%20service%20target%20performance%20incentive%20scheme%20-%20April%202015%20fixed.pdf p. 11-23.

Appendix D: White Paper on Transmission Technologies and Incentives

Bruce Tsuchida, Brattle Group
Rob Gramlich, Grid Strategies

Improving Transmission Operation with Advanced Technologies:

A Review of Deployment Experience and Analysis of Incentives

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Notice

This white paper was prepared for Americans for a Clean Energy Grid, Sustainable FERC Project, and the WATT Coalition. All perspectives and opinions are the authors and do not necessarily reflect those of The Brattle Group, its clients, or other consultants. However, we are grateful for the valuable contributions of many consultants of The Brattle Group, including Johannes P. Pfeifenberger as a peer reviewer.

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Where permission has been granted to publish excerpts of this white paper for any reason, the publication of the excerpted material must include a citation to the complete white paper, including page references.

Please direct any questions or comments to T. Bruce Tsuchida: Bruce.Tsuchida@brattle.com.

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Executive Summary

Various federal policies have helped stimulate transmission planning and associated investment activities in the last two decades, resulting in positive and observable changes. For example, annual investments in transmission by FERC-jurisdictional transmission owners grew by nearly 4-fold over the last decade—from approximately $5 billion in 2005 to nearly $20 billion in 2017, particularly in the RTO/ISO regions. However, these policies, while discussing the needs, may not have as successfully enhanced transmission operations—something that should be viewed as complementary to longer-term system expansion solutions. In the meantime, supported by recent years' technological advancement in power electronics, communication devices, computational processing power, and optimization algorithms, various technologies have been developed to aid the operational efficiency and capabilities of the transmission grid. These new commercially-available technologies have only a limited role in the U.S.

The slow change observed in improving the transmission grid's operational efficiency does not suggest that transmission operators[1] are not enhancing their practices. A prime example of improved operation may be how systems with a very high level of renewable penetration, at times now higher than 50%, are being operated without interruption—something that, ten years ago, many in the industry believed would be extremely challenging. At the same time, the under-utilization of new technologies designed to enhance operations could indicate that the existing transmission grid is not yet utilized to its maximum capability.

What are these new technology options and how much benefit do they provide? Examples of these new technologies discussed in this white paper are limited to roughly two types: those that explore enhanced and flexible application of the pre-determined transfer capability; and those that focus on flexible and dynamic control of transmission systems.[2] Dynamic line rating ("DLR") and adaptive line rating are applications that try to better address the individual line's transfer capability. Phase Angle Regulators ("PARs") and Flexible Alternating Current Transmission Systems ("FACTS")—a common name for power-electronic-based devices that allow for flexible and dynamic control of transmission systems—are examples of hardware solutions focusing on controlling the flow. Transmission topology control is an elegant software alternative to these flow control hardware—it controls the flow by adjusting the system topology (for example, by opening

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1 In U.S. RTOs and ISOs, the system operator operates the transmission system. This white paper will purposely distinguish the transmission operator from the system operator. A "system operator" in this white paper will point to the operator of an RTO or ISO. Given that transmission operation is one of the many services the RTO/ISO provides, a "system operator" counts as a "transmission operator" but not vice versa.

2 Many advancements have been made in grid-expanding technologies such as new conductor design; these technologies are not addressed in this white paper because the incentives to deploy them are different from those affecting management of the existing network.

or closing circuit breakers) and hence changing the flow distribution that is defined by Kirchhoff's Law to achieve operational objectives.

Compared to major new transmission investments, these operations-focused technology options can be put into service much faster and often for a small fraction of the cost. Many of these applications have been proven to be robust and effective. The economic benefits brought by the enhanced operational efficiency have been quantified in a number of studies and projects. Observations from these studies and applications indicate that the benefits of larger-scale deployments of these technologies in the U.S. can be in the tens to hundreds of million dollars—comparable to the scale of some of the operational benefits provided by RTO- or ISO-operated regional power markets, and yet often for a significantly lower cost and quicker installation. Importantly, these technology options are not necessarily competing with building new transmission—in fact, they are complementary to transmission expansion. They can magnify the cost effectiveness and capabilities provided by new transmission investments. An example may be new transmission investments that significantly increase transfer capacity relative to the existing system's transfer capacity. Such high-capacity projects tend to have their utilization limited by existing low-capacity lines. By using these technologies to relieve power flows on these low-capacity lines, the transfer capability provided by the new high-capacity lines can be better utilized, yielding a more favorable benefit/cost ratio. The new operations-focused technology options provide short-term solutions to temporary operational challenges, such as during transmission outages or the construction of new lines. They can bridge the gap until permanent expansion solutions can be put in place. The need for such technologies will likely rise as the pace of the industry's clean-energy transition accelerates.

Despite these quantified benefits, deployment of the new operational solutions is limited mostly to small-scale pilots in the U.S. There are two factors that can be thought of as the drivers behind this hesitancy. First, the technology options by themselves are not being recognized enough for their capabilities. The transmission grid has traditionally been thought of as having a fixed capacity and topology. Therefore, operational improvements may not be viewed as a potential source of increasing the grid's capability. And the newly-commercialized technology options to enhance transmission operations are not well understood, nor do many operators have much experience with them—in part, because many of the significant technology breakthroughs that enabled these technologies have happened only recently. Second, there are limited incentives for transmission operators and owners to innovate and change their operations, which requires a concerted and coordinated effort. The lack of incentives could potentially reinforce the first factor.

Thus, better incentives are needed. A key incentive mechanism may be "benefit-sharing" between the transmission operators, transmission owners (the operator and owner could differ), and other market participants. Insights from the ITC-RTO hybrid proposals (in response to FERC Order 2000) where a separate transmission operator exists under an RTO, or incentive mechanism examples from abroad, including those in the U.K. and Australia, may be useful in developing such incentive policies. Other immediately implementable steps may include directing the system operators to develop a protocol similar to that in ISO-NE, which warns against transmission owners for causing additional congestion during transmission outages, and to include these technology options in the system operators' transmission planning and operations decision-making processes, perhaps starting as an option to mitigate congestion during transmission outages. Just as utilities were able to adjust their operations to integrate large amounts of renewables penetrations within the last decade, they would be able to take advantage of these technologies once the appropriate incentive schemes are in place.

I. Introduction

The U.S. electricity market has been evolving and various federal policies aimed at enhancing transmission planning and operations have been designed and implemented in the last two decades. For example, Federal Power Act Section 219 (b) 3 added by the Energy Policy Act of 2005 ("EPAct") specifically points to "encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities." Various Orders from the Federal Energy Regulatory Commission ("FERC") that followed (including Order 679 from 2006)[3] have helped stimulate transmission planning and associated investment activities. Since issuing Order 679, FERC has acted on 109 incentive applications for over $80 billion in anticipated construction costs.[4] Annual nation-wide transmission investments grew from approximately $5 billion in 2005 to approximately $20 billion in 2017, with most of the investments taking place in the RTO/ISO regions.[5] There are many more players proposing and developing innovative transmission solutions and many RTOs/ISOs have been soliciting competitive bids.[6]

However, these policies, while discussing the needs, may not have successfully enhanced transmission operations—something that should be viewed as complementary to longer-term

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3 In 2011, FERC issued Order 1000 that was largely focused on transmission planning. In 2012, FERC issued an Incentives Policy Statement, partially as a follow up to Order 679, and to provide additional guidance regarding its evaluation of applications for transmission incentives. The Incentives Policy Statement included applications of new technologies to facilitate more efficient and reliable usage and operation of existing or new facilities, as an example of transmission project categories that may qualify for such incentives. The various regional transmission planning processes implemented in response to Order 1000 became effective between 2013 and 2015 (after the 2012 Incentives Policy Statement), reforming transmission planning and associated development.

4 FERC news release "FERC Opens Inquiry on Improvements to Electric Transmission Incentives Policy", March 21, 2019 (https://ferc.gov/media/news-releases/2019/2019-1/03-21-19-E-1.asp#.XQ78ZI8pBki)

5 Nation-wide transmission investments grew from approximately $5 billion in 2005 to approximately $20 billion in 2017, with most of the investments taking place in the RTO/ISO regions. These estimates are based on The Brattle Group analyses using FERC Form 1 investment (except for ERCOT for years 2010–2017, which are based on ERCOT TPIT reports), and EEI data (http://www.eei.org/issuesandpolicy/transmission/Documents/bar_Transmission_Investment.pdf.)

6 For example, there were initially over 20 different proposals submitted in response to New York's competitive solicitation (2015) to relieve congestion between upstate and downstate.

system expansion solutions. In 2011, after five years of experience with Order 679, FERC observed that "to date, the vast majority of applications for transmission incentives filed with the Commission have focused on the enlargement of facilities, including construction of new transmission facilities. Few applications have focused on the improvement, maintenance, and operations of transmission facilities or on increasing their capacity or efficiency…. For example, this could include software improvements that enhance scheduling and dispatch or investment in tools to enhance self-healing grid capabilities or improved situational awareness."[7] The magnitude of change observed for transmission operations has been much smaller, compared to transmission planning and associated investment activities.

The relatively slow change observed in improving the transmission grid's operational efficiency does not suggest that transmission operators are not enhancing their practices. For example, many in the industry may have once (as recent as ten years ago) believed that integrating variable renewable resources such as wind and solar at large amounts beyond 10% or 20% penetration levels would lead to severe operationally challenging situations. Today, systems with much higher penetration levels, at times higher than 50%, are being operated without interruption.[8] In general, operational changes tend to be marginal and not as apparent as new investments. However, this does not indicate that the transmission operators are taking advantage of all available options to enhance operations and maximize the capability of the existing transmission grid beyond what they can comfortably do with existing tools.

In reality, a large number of technology options—most of them taking advantage of recent technology improvements in electronics, communications, computational power, and optimization algorithms—has been developed. Compared to transmission investments, these technologies can be implemented much faster for a small fraction of the cost. Furthermore, these technologies are complementary to new transmission investments—they can be used to enhance the capability of the existing grid as well as magnify the capabilities provided by and the cost effectiveness of new transmission investments. The soundness of these new technologies has been demonstrated, and the benefits have been recognized, and in some cases, quantified, as the examples in the sections following will illustrate.

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7 Promoting Transmission Investment through Pricing Reform, Notice of Inquiry, May 2011, RM11-26, p.13.

8 There are a number of examples when more than half of the hourly energy served were produced by renewable resources. For an hour in hour in April 2019, over 66% of the energy served in SPP was produced by wind (https://www.aweablog.org/wind-breaks-new-record-southwest-power-pool/), in January 2019, over 56% of the hour's energy served in ERCOT was from wind (http://www.ercot.com/content/wcm/lists/172484/ERCOT_Quick_Facts_02.4.19.pdf), and in December 2018, over 70% of the hour's energy served in Xcel Energy Colorado was from wind (https://www.apnews.com/1566508ed5dd4f79ad2c89ec3a98cbe0).

II. Enhancing Transmission Operations

Enhancing transmission operations typically involves increasing the transfer capability of a congested path.[9] Transfer capabilities of transmission systems are defined largely by two factors—the physical capacity of individual lines and the network topology (including the points of injection and withdrawal) of these lines.[10] The physical capacity of an individual overhead line is defined primarily by the maximum operating temperature of the line, which directly affects how much the line will expand and sag.[11] Increasing power flow will warm the line due to resistive heating. Line temperature is affected by the ambient conditions and their cooling (or warming) effects, usually driven by temperature, solar insolation, and wind (both the speed and direction relative to the line).[12] Higher cooling effects allow more flow on the line. The network topology is a key factor that defines the distribution of the flows through the different lines that compose the system (including parallel flows or loop flows) based on Kirchhoff's Law, and hence, impacts the line temperature. The mainstream operational practice today is to maintain the flows within pre-determined line limits, which are often developed under a very conservative set of assumptions.[13] In many cases, a single limit is used for an extended period, such as for an entire season, or even longer. Setting seasonal limits somewhat accounts for different average ambient conditions and associated cooling effects, but nonetheless the practice of relying on a single limit over a long period is not ideal. It is akin to setting the highway speed limit at 40 miles per hour assuming snow storm conditions and applying that speed limit throughout the entire winter season, regardless of the actual road and weather conditions. Flows are maintained within these conservatively set limits by altering the generation dispatch—*i.e.*, typically reducing the output from a lower-cost generator upstream of the congested path and increasing the output from a higher-cost resource downstream. This approach leads to suboptimal economic efficiency, as can be represented by congestion costs.[14] The deregulated U.S. wholesale markets today, serving about two-thirds of the

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9 Path, in this white paper, will include both a single line and a set of lines.

10 In addition, there may be voltage and stability issues that could impact transfer capabilities. FACTS devices, discussed later, are commonly used to address some of the voltage and stability issues.

11 For some lines, there may be other limiting factors driven by temperature, such as the risk of annealing for copper conductors, and maximum current ratings of various devices attached to the line at either end ("terminal equipment").

12 Higher solar irradiation can offset such cooling effects.

13 In practice, operations take into account contingencies and therefore the physical limit of a single line discussed above may not be the limiting operational constraint. More often, the post-contingency constraints (for example, the ratings for a given path accounting for the loss of a parallel path) becomes the binding constraint.

14 The impact of congestion can be measured in several ways. The RTO/ISOs commonly report "congestion costs" using the shadow price of congestion (*i.e.*, how much savings would there be if an additional MW of power could flow through the given path) multiplied by the path flow. Alternative measures of congestion may compare the production cost difference (through simulations *etc.*) of a system with and

nation-wide load, face about $3.9 billion of congestion costs a year.[15] If the congestion costs are proportional for other regions, the nation-wide annual congestion cost estimate could approach nearly $6 billion. While congestion costs depend on other variables, such as load, resource mix, and prevailing fuel prices, it is a significant sum that is ultimately paid by market participants.

The traditional thinking is that transfer capability can be increased only by upgrading existing lines or adding new lines, both of which require significant capital expenditures and multiple years of planning and development, on top of challenging regulatory hurdles and stakeholder processes. However, technology options with lower cost and faster implementation to increase the transfer capability of transmission systems—in both real time and operations planning timeframes—have been developed in recent years. Some of these new technology options explore enhanced and flexible application of the pre-determined transfer capability. Dynamic line rating ("DLR") and adaptive line rating are applications that try to better address the individual line's transfer capability. Other technology options, such as Phase Angle Regulators ("PARs")[16] and Flexible Alternating Current Transmission Systems ("FACTS"), focus on controlling the flow.[17] PARs are transformers with switches that are specially configured to control power flow. FACTS are power-electronic-based static devices that allow for flexible and dynamic control of flow on transmission lines or the voltage of the system. Transmission topology control is an elegant alternative to these flow control devices—it controls the flow by adjusting the system topology (for example, by opening or closing circuit breakers) and hence changing the flow distribution that is defined by Kirchhoff's Law to achieve operational objectives. This section describes these technologies and their benefits through examples.

A. Dynamic and Adaptive Line Rating

DLR utilizes real-time measurements of the line temperature and/or sag. This can be done by directly measuring the line temperature, tension or sag, or by measuring the ambient conditions in the field and thereby determining the weather's cooling effects on the lines. Ambient conditions, including air temperature, humidity level, solar irradiance, wind speed, and direction, all impact the net cooling effect. For example, windier conditions will have increased cooling effects and can lead to higher transfer capabilities. At a high level, applying DLR under a higher wind speed

without the path in question being congested. Note that these different measures may not be directly comparable between each other. This white paper distinguishes congestion costs (adhering to the RTO/ISO convention) and change in production costs.

15 The annual congestion costs estimated by each RTO/ISOs for 2016 are: $1,400 million for MISO; $1,024 million for PJM; $529 for NYISO; $497 million for ERCOT; $280 million for SPP; $142 million for CAISO; and $39 million for ISO-NE, totaling $3,911 million for these markets.

16 PARs are also known as Phase Shifting Transformers or Quadrature Boosters.

17 While PARs and FACTS can be considered substitutes (functionally), this white paper distinguishes PARs as transformer-based technology and FACTS devices as power electronic-based technologies that may be mobile.

condition can be ideal for reducing wind curtailments because when the wind is stronger, the increased transfer capability allows delivery of energy when wind plants are generating more.[18]

A DLR study performed by Oncor Electric Delivery Company in 2013[19] shows that significant congestion mitigation can be obtained with as little as a 5 to 10% increase in capacity over the currently used line ratings.[20,21] Based on the demonstration project findings, Oncor estimates that if one-twentieth of ERCOT transmission lines were outfitted with DLR technologies, the total savings from congestion reductions would amount to approximately $20 million, or a 3% reduction in congestion costs.[22] In addition, Oncor finds the DLR system to be highly reliable and accurate, providing 24/7 functionality and measuring average conductor temperature accurate to 1–2 degrees Celsius. Another significant study outcome is that Oncor successfully transmitted dynamic ratings directly to ERCOT (starting in May 2012) by streaming data into ERCOT through Oncor's EMS. This, at the time, represented an industry breakthrough, as a real-time data feed of dynamic ratings to a system operator's Security Constrained Economic Dispatch tool had never been implemented before.

More recently in 2017, American Electric Power ("AEP") and LineVision (a vendor of transmission line monitoring systems) field tested a DLR system, and showed increased capacity over ambient-

18 On the other hand, solar resources may face the opposite effect because increased heat from solar radiation during high production hours could reduce the transfer capabilities.

19 The ONCOR study, together with a separate study undertaken by the New York Power Authority, was performed as part of the U.S. Department of Energy's Smart Grid Program. See "Dynamic Line Rating Systems for Transmission Lines, April 25, 2014" (https://www.smartgrid.gov/files/SGDP_Transmission_DLR_Topical_Report_04-25-14_FINAL.pdf.)

20 ONCOR uses ambient-adjusted ratings where the static ratings are adjusted "daily, hourly, or…more frequently to account for different ambient temperatures." As ambient-adjusted ratings already account for weather changes, albeit at a slower rate than DLR, it can be assumed that the increased real-time capacity for the lines in this demonstration project would have been even larger if the lines were operated using static ratings. Generally, dynamic ratings are found to be 5%–25% greater than the static rating.

21 Oncor has noted that a transmission owner typically requires only 5%–10% additional capability above the static rating to address most congestion issues. In this analysis, Oncor determined that 5% additional capacity could relieve congestion by up to 60% on the target lines with DLR installed, while 10% additional capacity would practically eliminate all congestion on the target lines. The DOE report (see footnote 19), which includes the ONCOR study, notes that a 3 feet per second increase in wind speed at a 90 degree angle to the line increases the transfer capacity by 44%.

22 The ONCOR study demonstrates that the effective congestion mitigation could be in the range of 60% to 100% on the lines monitored, and suggests that a 5% increase in transfer capability using DLR could lead to a 3% reduction in annual wind curtailment, with the largest monthly reduction exceeding 40%.

adjusted ratings over 90% of the time.[23] A second study performed by PJM and LineVision focused on three sections of a highly congested transmission line.[24] The study utilized historically observed weather conditions to determine that dynamic ratings showed a net congestion cost savings of $4.2 million annually. The one time DLR installation and implementation costs were estimated to be approximately $0.5 million. LineVision performed a similar study with AEP and the Southwest Power Pool ("SPP"), demonstrating how a DLR system installed on a 2.1-mile segment of a target transmission line in the SPP region can reduce congestion costs.[25] Applying the ratings from the DLR system, the parties identified opportunities to save approximately $18,000 during just 300 minutes of real-time grid congestion.[26] This indicates the annual savings of a single DLR system can be in the range of a few million dollars (approximately $6.5 million, if similar saving opportunities can be found every day).

The value of DLR was demonstrated during the 2018 "bomb cyclone" where much of the grid in the northeastern U.S. was constrained due to an extended cold snap between late December 2017 and January 2018. During this extreme weather event, ISO New England ("ISO-NE") issued an abnormal conditions alert to address both the weather and supply concerns, and increased their transmission line ratings to allow for greater line capacity. One ISO-NE report stated "At 16:00 on 1/3/18, the scheduling limit on the New York A.C. 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."[27] Technically, ISO-NE only used ambient-adjusted line ratings[28] to avoid large quantities of congestion as generated by the bomb cyclone.

Outside the U.S., the Belgium transmission system operator Elia worked with Ampacimon (a DLR system vendor) to study DLR systems on eight of ten critical transmission interconnectors with

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23 See Marmillo, J., Pinney, N., Mehraban, B., Murphy, S., and Dumitriu, N. (2018), (https://watttransmission.files.wordpress.com/2018/10/cigre-gotf-2018-ngn-pjm-aep-linevision-final.pdf)

24 Line Vision and AEP deployed and tested DLR on the Cook-Olive 345 kV line for the month of January 2017. The DLR system deployed was removed after the study.

25 The DLR system deployed was removed after the study.

26 SPP was able to duplicate real-time market results for both static and DLR cases to compare prices for the 300 minutes of congestion, which was determined by the equation: RTBM Operating Cost = (Startup Cost) + (No Load Cost) + (Incremental Energy Cost) + (Ancillary Service Cost) + (Transaction Costs)

27 See slide 41 of ISO-NE presentation "Cold Weather Operations, December 24, 2017–January 8, 2018" (http://www.nepool.com/uploads/NPC_20180112_Cold_Weather_Ops.pdf)

28 This suggests that ISO-NE may not have captured the full benefits of DLR. See footnote 20 for discussion on ambient-adjusted line ratings.

France and the Netherlands during the winter of 2014–2015.[29,30] Subsequently, Elia deployed a utility-wide DLR system[31] with over 150 sensors installed on 30 transmission lines, which has helped Elia increase exchange capacities with surrounding countries (France, Netherlands, Luxembourg, and Germany). Elia identified over $0.26 million of congestion savings provided by DLR during a four-hour instance of congestion alone[32] by allowing for the additional import of 33 MW.

Adaptive line rating, developed by ISO-NE, changes the post-contingency transfer capability based on the length of time the system takes to respond to a contingency event. Normally, a conservative estimate of the response time is used to calculate the post-contingency transfer capability. For example, many post-contingency transfer capability is often calculated as "what would be the maximum transfer that can constantly flow for 30 minutes" rather than the more realistic assumption that the post-contingency flow will be reduced over time (and therefore the heating caused at the maximum flow level will not be sustained over time). With a more accurate time estimate, adaptive line rating allows the post-contingency rating to be higher, with the knowledge that the system can reduce the post-contingent flow before the line temperature reaches its limit. Since most transmission constraints tend to be contingency constraints, increasing post-contingency transfer capabilities can be very effective in reducing congestion and associated renewable curtailments. ISO-NE anticipates that implementing adaptive line ratings would increase post-contingency ratings by 11% on average, and eliminate congested bottlenecks 44% of the time.[33] Implementation of adaptive ratings does not require any hardware, it is implemented by modifying or enhancing operations (and planning) software.

B. Flow Control Devices

PARs and FACTS devices help the transmission operator control flow through a given path. Power flow through an AC line is proportional to the sine of the difference in the phase angle of the

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29 Bourgeois, R. and Lambin, J. (2017), "Dynamic Ratings Increase Efficiency," March 8, 2017, (https://watttransmission.files.wordpress.com/2018/01/ampacimon-dynamic-ratings-increase-efficiency_belgium-transmission-grid.pdf)

30 Skivee, F., Godard, B., Vassort F., Bourgeois, R., and Lambin, J. (2016), "Integration of 2 days-ahead capacity forecast to manage Belgian energy imports," (http://www.ampacimon.com/wp-content/uploads/2016/09/Cigre_C2_PS1__20161.pdf)

31 The DLR sensors are maintenance and calibration free and use 3D accelerometers and conductor vibration analysis to accurately (with less than 1% error) measure sag, effective perpendicular wind speed and conductor temperature on critical spans of the transmission lines.

32 The case study in Belgium quantified congestion savings using a 48-hour weather forecast to establish the DLR.

33 Maslennikov, S. and Cheung, K., "Prototyping and Testing Adaptive Transmission Rates for Dispatch," presented at FERC Technical Conference Increasing Market Efficiency through Improved Software, Docket AD10-12-003, Washington, DC, June 2013.

voltage between the transmitting end and the receiving end of the line. PARs control the flow through a given line by directly manipulating this angle.[34] While PARs are widely accepted in the industry, the largest drawback[35] is the cost—for example, a recently-installed PAR between Michigan and Ontario has an annual carrying cost of over $10 million, making the installation of multiple PARs throughout the system a costly option. FACTS[36] are generally power-electronic-based devices. Some FACTS devices alter the reactance of a line to control the flow (*i.e.*, increasing the reactance will push away flows while decreasing the reactance will pull in more flow to the line). For example, series capacitors have been applied in power systems to increase transfer capability of long transmission lines for a number of years.[37] These devices typically cost significantly less than PARs, can be manufactured and installed in a shorter time, are scalable, and in many cases, are available in mobile form that can be easily redeployed.[38]

In 2016, DNV GL conducted a study on the economic benefits of deploying FACTS-based flow control devices in the PJM system. The study evaluated a future PJM system in 2026 with 30% of its energy sourced from renewable resources (onshore and offshore wind and solar PV), and adds FACTS devices on select lines higher than 100 kV (in addition to conventional transmission enhancements). DNV GL finds the deployment of flow control devices with an estimated annual investment cost of $81 million would produce PJM region-wide savings of $890 million per year—a combination of $267 million reduction in annual transmission spending, and $623 million in production cost savings.[39] DNV GL observed there may be further savings, such as the potential to reduce up-front interconnection costs for renewable resources.

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[34] For example, if there are parallel circuits with different capacities between two points, direct manipulation of the phase angle allows control of the division of power flow between the paths.

[35] Installing PARs typically requires a larger footprint and longer lead-time compared to the newer FACTS devices. Legacy versions of FACTS devices, such as thyristor-controlled series capacitors ("TCSCs"), static synchronous compensator ("STATCOM"s), and unified power flow controllers ("UPFCs"), have similar costs, footprints, and lead-time requirements as PARs.

[36] Some FACTS devices, such as the series capacitor and static VAR compensator ("SVC"), are well known and widely used in power systems today.

[37] Series capacitors will reduce the series inductive impedance of a transmission line. This reduction brings benefits for voltage and reactive power control, and increased transient and steady-state stability limits.

[38] Some of the FACTS devices introduced over the last two decades are modular and allow the solution to be quickly scaled to match the system need. These modular devices can be redeployed as needed, and will reduce capital cost needs. Smart Wires estimates material acquisition to take only a few months and a typical installation can be completed in a matter of weeks. See "A Flexible Future: Addressing Uncertainty in the Grid with Innovative Power Flow Control Technology" (https://www.engerati.com/system/files/grid_symposium_ebook.pdf)

[39] These values are expressed in 2026 dollars. Adding these FACTS-based flow control devices reduced new line miles by 24% and reconductoring line miles by 45%, leading to the $267 million drop in annual transmission spending.

Also in 2016, Pacific Gas and Electric Company ("PG&E") reviewed the construction and on-going operation and maintenance costs of Distributed Series Reactors ("DSRs") as an alternative to mitigating the thermal overloading of a 230 kV line.[40] Installing approximately 2,000 DSR units on this 230 kV line at an estimated cost of approximately $33 million indicated almost a 75% cost savings compared to reconductoring the line at an estimated cost of approximately $130 million.[41] The study results show 99.9% availability of these devices with a correct operating state 99.99% of the time. However, recent transmission planning studies' lower load projection (largely due to energy efficiency and distributed energy resources) indicate significantly lower thermal overloads and questions the need of the DSRs.

More recently, the Electric Power Research Institute ("EPRI") evaluated the costs and benefits of using flow control devices to reduce congestion or meet reliability standards. Simulating the 2016 PJM system with 13 power flow control devices placed in optimal locations to reduce thermal overloads indicated annual production cost savings of $67 million. Considering the initial investment cost of $137 million, the payback period is roughly 2 years.[42,43] In the same study, EPRI looked at the SPP system and analyzed if flow control devices could defer transmission investments. In many cases these alternative technologies provided costs savings—for example, using two FACTS devices to remedy thermal overloads of an existing line would cost only between $1.5 million and $5.2 million, compared to installing a new 115 kV line at a cost of $16.8 million.[44]

Flow control devices played a major role during the aforementioned 2018 cold snap event in the northeast U.S. During this event, the New York Independent System Operator ("NYISO") saw a 50% to 100% increase in downstate prices (in particular, Zone J: New York City, in comparison to the Western region, Zone A: West), and initiated several NERC Transmission Loading Relief ("TLR") alerts.[45,46] The two Ramapo PARs enabled NYISO to direct flows from PJM into eastern New York using its 500 kV path. NYISO has publicly acknowledged the reliability benefits that

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40 PG&E successfully deployed DSRs to detect potential overloads and shift load to parallel lines. The DSR is a modular flow control device and can be scaled up or down to match the specific needs.

41 PG&E concluded that the annual operations and maintenance cost estimates were relatively low.

42 The load payments decreased by $189 million. See pages xii and xiii of "Benefits and Value of New Power Flow Controllers, 2018 Technical Report" (https://www.epri.com/#/pages/product/3002013930/?lang=en-US).

43 Product performance and function have improved significantly in the last five years. For example, compared to the device that was studied by EPRI, a subsequent product developed shows 200 times the control ability per device and are 60% lighter in weight.

44 Another example included was using a FACTS device to defer reconductoring a 115 kV line and upgrading 230/115 kV substation by over ten years. See footnote 42.

45 See slide 13 of Yeomans, Wes (2018), "Winter 2017–2018 Cold Weather Operations" (https://www.nyiso.com/documents/20142/1394512/Winter%202018%20Cold%20Weather%20Operating%20Conditions.pdf/76900f56-ccca-3ffa-b1f2-78618fcff7c7)

46 A TLR alert is initiated when transmission schedules are curtailed due to congestion.

their PARs have previously provided: "The control capability provided by the two Ramapo PARs increases operational flexibility for NYISO. Power injections can be directed where needed for reliability."[47]

C. Topology Control

Transmission topology control (or topology optimization) is a simple and elegant application of flow control using existing hardware deployed on the transmission grid (circuit breakers and communication systems) and is untapped by software. Topology control improves the overall transfer capability of the system by changing the distribution of the power flow on any individual line. For a given system, the flow distribution depends on location and levels of generation and load, and the transmission topology that connects the generators and loads. By strategically opening or closing certain circuit breakers, this technology can redistribute the flow away from a constrained part of the system to other parts of the system with spare capacity. Because this is a software application, the cost can be quite low compared to most hardware solutions.

The concept of topology control is not new and has been used mostly as "operating guides" to address reliability concerns. For example, it has been a common practice to open a constrained low voltage line if the load can be carried on a higher-voltage line. PJM has a list of potential transmission switching procedures identified to reduce or eliminate transmission system congestion.[48] However, most of these switching procedures are developed based on the operators' experience and are time-consuming to create and evaluate. Recent developments of topology optimization software allows the system operator to systematically and automatically identify beneficial system reconfigurations, analogous to the way a GPS-based map-application quickly finds alternative routes when there is road congestion. These software technology developments have rendered topology control to be a practical solution for quickly identifying beneficial reconfiguration of the transmission grid.[49]

An ARPA-E project led by Boston University (which included PJM as a team member) simulated the economic benefits of AC-based topology control using three representative weeks (one week per season—*i.e.*, summer, winter, and shoulder) of historical (2010) PJM real-time energy markets, selected with PJM guidance. Using these three weeks as points of reference, the study estimates

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[47] See slide 13 of Yeomans, Wes (2017), "Ramapo Phase Angle Regulator Cost Recovery Discussion," April 10, 2017 (https://www.nyiso.com/documents/20142/1410851/MIWG%20-%20Ramapo%20PAR%20Cost%20Allocation%20-%20April%2010%202017%20Final%20ppt.pdf/f32bc71f-a2a2-0c40-3106-8f695002a0ca)

[48] See PJM, Switching Solutions(https://www.pjm.com/markets-and-operations/etools/oasis/system-information/switching-solutions.aspx)

[49] Market participants generally see formulated and systematic procedures as a better option to decisions that fully depend on the operator in charge, which may appear as arbitrary to an external observer.

the PJM-wide annual production costs savings under real-time 2010 market conditions to be over $100 million.[50]

More recently, in 2018, The Brattle Group and NewGrid (a topology control software vendor) studied the benefits of topology optimization for the SPP market. The study, which uses 20 real-time snapshots of the entire SPP system selected by SPP as a representative set of complex grid conditions, finds that topology reconfiguration options can generate real-time production cost savings that range between 2% and 5% of the initial congestion costs of the relieved constraint. Based on historical congestion costs, the estimated real-time market production cost savings from using topology control are $18 to $44 million annually.[51]

Some European studies focusing on topology optimization benefits have used algorithms developed in the U.S. Beginning in 2015, National Grid (U.K.) conducted a year-long study investigating the feasibility of adopting existing topology optimization algorithms for their service territory. Using historical data from 2016 and 2017, the study demonstrates that topology optimization could increase transfer capacity across large, heavily binding transmission constraints, such as into the London metropolitan area, by 3% to 12%. This translates to production cost savings of £14 to £40 million (approximately $18 million to $52 million)[52] annually to end consumers.[53]

D. Other Applications of these Technologies

The application and benefits of these new technologies are not limited to reducing congestion under normal system conditions. For example, flow control technologies (including topology control) can be used to direct flows away from critical transmission lines for other shorter-term purposes, including to improve the system reliability and resilience, and improve system operations in general, as illustrated by the following studies and pilot applications.

In 2018, The Brattle Group worked for a G&T electric co-op in an RTO market. Due to planned transmission outages that took place over four months, the co-op's main power plant was subject to severe congestion that limited its output and reduced its nodal prices compared to the co-op's load center. Using topology optimization software, The Brattle Group identified reconfiguration solutions that would fully mitigate this congestion. The co-op discussed the solutions with RTO

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50 Ruiz, P.A., *et al.*, "Transmission topology optimization: simulation of impacts in PJM day-ahead markets," presented at FERC Tech. Conf. on Increasing Market Efficiency through Improved Software, Docket AD10-12-005, Washington, DC, June 2014.

51 Ruiz, P., *et al.*, "Transmission topology optimization: congestion relief in operations and operations planning," SPP Market Working Group Meeting, Oct 2018.

52 Assumes historical exchange rate of approximately 1.3 USD per GBP.

53 Annual constraint costs across the entire Great Britain totals approximately £ 340 million. See National Grid, Network Innovation Allowance Closedown Report, Transmission Network Topology Optimisation, project NIA_NGET0169, Jul 2017. (http://www.smarternetworks.org/project/nia_nget0169/documents)

staff, which validated the reconfigurations and its impacts. However, the reconfigurations were not implemented as the owner of the transmission assets to be reconfigured declined to do so, arguing that the outages that caused the congestion were not located in its footprint. Since the reconfigurations were not implemented, the co-op members incurred about $4 million in congestion costs during the 4-month transmission outage period.

In 2015, Smart Wires (a vendor of modular FACTS devices) performed a study analyzing the potential benefits of modular FACTS devices to support construction of new transmission lines. The utility needed to upgrade two 60 kV lines to two 115 kV lines. Given the length and location of the lines (70 miles long over a difficult terrain) and the need to replace the towers (from wood poles to steel towers), the estimated construction period was 3.5 years. Taking out the two 60 kV lines required redispatch of generation, particularly in the summer season, to avoid overloading other nearby lines. The study identified that the redispatch could be avoided by installing modular FACTS devices and rerouting the flow from these otherwise overloaded lines. The annual costs of the modular FACTS devices were estimated to be between $1.5 million and $4 million, and the savings from avoiding redispatch were estimated to be over $20.5 million a year, therefore suggesting a net savings of $61.5 million to $69.7 million over the construction duration period of 3.5 years (depending on when the construction starts).

During the Polar Vortex event of 2014, The Brattle Group supported a utility in the upper Midwest to mitigate congestion and overloads under those critical conditions. In the course of that event, the Midcontinent Independent System Operator ("MISO") experienced record-setting high loads due to extreme cold weather. The extreme low temperatures led to a substantial number of unplanned generation outages. The very high loads and generation outages combined with extended 230 kV planned transmission outages led to severe post-contingency 115 kV transmission congestion and overloads affecting transmission utilities in the upper Midwest. The heavy congestion and overloads resulted in load energy prices in the affected areas that at times more than doubled the corresponding generation energy prices, increasing the cost of electricity in the affected areas by over $15 million in the first 10 weeks of 2014. The Brattle Group performed topology optimization analyses for one of the utilities impacted, identifying reconfiguration solutions that relieved much of the congestion and overloads. These solutions were implemented by MISO after validation and discussion with the transmission owners in the area. The performance of topology optimization under those severe conditions illustrate the resilience benefits of flow control technologies

The same approach can be applied for various events that may temporarily change the flow pattern—including transmission outages, generation outages, and other short-term projects that may entail a large amount of power consumption. Another application is to direct power flows to a set of target transmission lines.

In 2018, SPP analyzed the benefits of flow control using topology control to heat lines during severe winter conditions to avoid icing.[54] The study was performed for the January 2017 Winter Storm Jupiter conditions, which caused multiple transmission outages due to ice accumulation. Given the challenging conditions for restoration, some of these outages lasted over a full day. The study identified two reconfiguration solutions that could have prevented or significantly relieved the ice buildup on selected critical lines, while meeting reliability criteria. The estimated savings of avoiding the hypothetical outages of these critical lines are $10 to $17 million, in addition to avoided system restoration costs.[55]

DLR has been used to help integrate intermittent renewable resources. Often the same wind conditions that turn turbines are also cooling lines. There is a high degree of overlap between wind production and DLR-induced allowable power flow. The European studies listed below generally indicate that DLR can reduce renewable curtailments by about 15%.[56]

The Belgium transmission system operator Elia installed DLR systems on two lines (Slijkens-Brugge line in 2010 and Brugge-Langerbrugge line in 2014), which connect off-shore wind to the Belgian grid. The average capacity gain on the 150 kV sub-transmission Brugge-Langerbrugge line was 116%, thereby reducing potential curtailments.[57] Similarly, DLR systems were evaluated on lines in the U.K. (132 kV double-circuit lines in northeast of England and a 110 kV line in Northern Ireland) and demonstrated that 30% more wind generation was connected to the grid through the 132 kV line.[58] DLR pilot cases were studied for two lines in Italy, aimed at maximizing the

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[54] This was a well-known practice many decades ago, see Smith, H. B. and Wilder, W.D., "Sleet-melting practices—Niagara Mohawk system," *Transactions of the American Institute of Electrical Engineers. Part III: Power Apparatus and Systems*, Vol. 71, Issue 3, Aug 1952, pp. 631–634.

[55] See Ruiz P., *et al.*, "Transmission topology optimization: pilot study to support congestion management and ice buildup mitigation," SPP Technology Expo, Nov 2018.

[56] See slide 12 of Ampacimon's presentation "Wind Integration Use Case" (https://watttransmission.files.wordpress.com/2019/06/wind-integration-use-case.pdf)

[57] *Id.,* slide 9

[58] See conference paper "Dynamic line rating protection for wind farm connections" (https://www.researchgate.net/profile/Graeme_Lloyd/publication/224580948_Dynamic_line_rating_protection_for_wind_farm_connections/links/54eb2e3f0cf27a6de1175153/Dynamic-line-rating-protection-for-wind-farm-connections.pdf?origin=publication_detail). See slide 14 of Ampacimon's presentation "Wind Integration Use Case" (https://watttransmission.files.wordpress.com/2019/06/wind-integration-use-case.pdf)

generation by renewable energy resources, particularly wind, and to increase N-1 security.[59] A Swedish distribution system operator concluded that DLR can reduce wind curtailment by 15%.[60]

E. Potential Benefits and Actual Deployments

As the examples discussed above demonstrate, the potential benefits of these technology options are quite significant, with estimated benefits ranging in the tens to hundreds of million dollars per year with large-scale deployments.

As a reference point, these benefits are of the same magnitude as some of the operational benefits provided by RTO and ISO-operated regional markets. For example, PJM estimates that managing the transmission system through nodal power markets instead of using TLR processes saves about $100 million a year. PJM estimates an additional $100 million a year in benefits due to the reduced need of its Grid Services (regulation and synchronized reserves that help maintain the stability of the grid) because of its broad geographical scope.[61] Similarly, MISO estimates the combined benefit of pooling regulation and spinning reserves from different resources across its footprint to be in the range of $61 million to $68 million per year.[62] The Western Energy Imbalance Market ("EIM") experience shows approximately $650 million in gross benefits for the period of November 2014 through March 2019, which is just shy of $150 million per year.[63] In 2015 when the Western Area Power Administration known as the Upper Great Plains Region was pursuing membership in an RTO, it concluded that joining SPP would yield long-term economic benefits pegged to be $11.5 million in the first year, growing to more than $14 million annually in later years.[64] SPP estimates the first year savings from its EIM (launched in 2007, at a cost of $33 million) to be approximately $103 million.[65] The examples of the operational enhancement technologies indicate that

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59 See Carlini, E. M., Massaro, F., Quaciari, C., "Methodologies to uprate an overhead line. Italian TSO case study" (https://journal.esrgroups.org/jes/papers/9_4_4.pdf). See slides 15 and 16 of Ampacimon's presentation "Wind Integration Use Case" (https://watttransmission.files.wordpress.com/2019/06/wind-integration-use-case.pdf)

60 See slide 17 of Ampacimon's presentation "Wind Integration Use Case" (https://watttransmission.files.wordpress.com/2019/06/wind-integration-use-case.pdf).

61 PJM value proposition website (https://www.pjm.com/about-pjm/value-proposition.aspx).

62 MISO value proposition website (https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-value-proposition/)

63 Western EIM benefits website (https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx)

64 Energywire news article "Southwest Power Pool launches new market, is poised to double in size," Friday, February 28, 2014 (https://www.eenews.net/stories/1059995285)

65 See page 2 of report "A Proposal for SPP's Western Energy Imbalance Service Market" (https://spp.org/documents/60104/a%20proposal%20for%20spp's%20western%20energy%20imbalance%20service%20market.pdf)

systematic deployment of these technologies can achieve savings that are of a similar magnitude of these RTO-associated savings.

A 2004 FERC staff report estimates the investment costs for establishing "Day One" operations (which does not include bid-based, security-constrained economic dispatch, unit commitment, locational prices, financial transmission rights, or capacity markets) for PJM, MISO, ERCOT, and SPP to range between $38 million and $117 million.[66] In the same report, FERC staff estimates the annual revenue requirement for Day One operations to be between $35 million and $78 million.[67] Some indicated that the 2004 FERC staff estimate that assessed Day One operations and ignored other functions as not being realistic. A 2010 paper[68] estimates the costs for a hypothetical RTO characterized as an open-access transmission service provider with varying levels of market functions (including a real-time energy, ancillary services, and congestion hedging mechanisms) being implemented to cost somewhere between $70 million and $180 million.[69]

Comparatively, deployment of the operational technologies discussed in this white paper require a much smaller investment— at most usually less than $10 million[70] to address a congested path— and ongoing costs in many cases are negligible, compared to the revenue requirement estimated for the Day One operations. Furthermore, they require less time to put into service. Most of the required investment is for small hardware (for measuring the ambient conditions including temperature, solar irradiance, wind, humidity, or the actual transmission line's temperature or sag level, FACTS hardware, or new circuit breakers to enable switching), or software (for example, for topology control). There is no need to build new lines or gain the rights of way for new paths so the development and installation are quick. Such speedy implementations can fill in the time lag until more extensive transmission investments can be placed in service, during outages, or as a

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66 See page ii of "Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization" Docket No. PL04-16-000 (https://www.ferc.gov/EventCalendar/Files/20041006145934-rto-cost-report.pdf)

67 FERC staff estimates the investment costs to set up Day One operations as PJM: $70 million, MISO: $117 million, ERCOT: $114 million, and SPP: $38 million. Annual revenue requirement estimates are PJM: $78 million, MISO: $73 million, ERCOT: $64 million, and SPP: $35 million. The report indicates the cost for setting up for Day Two operations to range between $100 million and $250 million.

68 See Greenfield, D. and Kwoka, J., "The Cost Structure of Regional Transmission Organization." (https://pdfs.semanticscholar.org/fb7c/c06ffd0690c240993291c2c7005de94b2327.pdf)

69 The paper estimates the base cost as an open access transmission provider (a similar function to the Day One operation needs discussed in the 2004 FERC staff report, see footnote 66) to be $68 million, with incremental costs of adding various other market functions as $37 million for a real-time energy market, $56 million for a real-time energy and ancillary services markets, and $27 million for zonal transmission rights, or $57 million for day-ahead and nodal financial transmission rights as an alternative to a zonal transmission right market. These cost estimates are comparable to those from the 2004 FERC staff report.

70 As the case studies introduced in this white paper show, many solutions are available in the $2 million to $5 million range. Some of the lower-cost solutions are less than $1 million.

permanent solution in circumstances in which a transmission expansion option is not possible due to economic or regulatory reasons.

These significant benefits, lower investment, and faster implementation have led to a number of deployments in the U.S. and globally.

Entergy has adopted the use of DLR (referred to by Entergy as Temperature Adjusted Ratings) on a number of transmission facilities for real-time operations in the MISO market.[71] By adjusting line ratings using ambient temperature during off-peak periods hourly, daily, and two days ahead of operations, Entergy has found that line capacity increases an average of 11% compared to base facilities ratings. Entergy believes the use of short-term emergency ratings can be expected to deliver the most significant congestion relief benefits and resulting savings to the MISO markets.[72] However, Entergy is cautious of a wide-spread deployment of the technology, siting unknown impacts to reliability and equipment—for example, the potential to degrade the applicable transmission facility or reduce its operating life. Consequently, in coordination with MISO and MISO's Independent Market Monitor ("IMM"), Entergy limits the application of DLR to facilities from which the use of such ratings is expected to deliver maximum value to the MISO markets.

Other North American jurisdictions that have deployed DLR include Dominion Energy and BC Hydro in British Columbia, Canada.[73] Outside North America, the European Network of Transmission System Operators for Electricity ("ENTSO-E"), which represents 43 electricity transmission system operators from 36 countries across Europe, confirms (as of 2015) that 11 transmission system operators in Croatia, Denmark, Germany, Hungary, Italy, Poland, Slovenia, Spain, and Switzerland have implemented, or are testing, DLR in their systems, although most of them are small-scale projects for select lines.[74]

FACTS devices have been installed and deployed by TVA on a 161 kV line in Knoxville, TN,[75] and by Georgia Power on two 115 kV lines. Smart Wires has been awarded contracts to install FACTS devices on a 230 kV line, just north of San Francisco, CA.[76]

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71 Entergy (2018), Entergy Practices—Dynamic Line Ratings, December 13, 2018, https://cdn.misoenergy.org/20181213%20MSC%20Item%2004a%20Entergy%20Presentation%20Dynamic%20Line%20Ratings300974.pdf.

72 For facilities on which DLR are used, Entergy provides dynamic ratings to MISO on an hourly, daily, and 2-day ahead basis.

73 BC Hydro Engineering Newsletter, January 2017.

74 See page 16 of ENTSO-E (2015), Dynamic Line Rating for overhead lines—V6 (https://docstore.entsoe.eu/Documents/SOC%20documents/Regional_Groups_Continental_Europe/Dynamic_Line_Rating_V6.pdf)

75 The TVA device was installed in 2012 and is still in service.

76 See pages 106, 110, and 111 of "CAISO 2017–2018 Transmission Plan" (http://www.caiso.com/Documents/BoardApproved-2017-2018_Transmission_Plan.pdf)

Outside of the U.S., EirGrid has installed and deployed modular FACTS devices. EirGrid first initiated a trial installation of three DSR flow control devices on a 110 kV line in Ireland in 2015. The following year, EirGrid installed three Smart Wires flow control devices on a 100 kV line. During the Smart Wires trial, Ireland was hit by Hurricane Ophelia, and Met Éireann (the national meteorological service in Ireland) issued a Status Red wind warning—the highest threat level possible. Ireland's south and west areas where these devices were installed faced strong gusts, sometimes up to 95 miles per hour. Yet, no structural damages were confirmed on these devices—the three devices installed remained intact and fully operational during the storm. Furthermore, these devices did not damage any of the transmission assets either. After a successful trial, the devices were removed. Elsewhere, Smart Wires flow control devices are being installed on a 132 kV line near Colchester of the UK Power Networks,[77] on a TransGrid 330 kV line that impacts transfers between Victoria and New South Wales, Australia,[78] and on an ElectraNet 132 kV line in South Australia.[79] Globally, more than 450 Smart Wires modular flow control devices have been installed on lines ranging from 63 kV to 230 kV.[80]

ERCOT currently uses topology optimization software in operations planning, including to support the review and development of its Constraint Management Plans ("CMP")—which includes a set of predefined transmission system actions executed in response to system conditions to prevent or resolve transmission security violations or to optimize the transmission system.[81]

Following the aforementioned 2018 SPP topology optimization study, SPP conducted a topology optimization pilot. As part of the pilot, SPP used reconfigurations found with topology optimization software to successfully relieve transmission overloads.[82] Some of these

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77 See article titled "Power capacity boost through innovation" (https://www.oxfordprospect.com/electricity/power-capacity-boost-innovation/) and project report titled "UKPN Loadshare Project" (https://www.smartwires.com/papers/)

78 See TransGrid Revenue Proposal 2018/19–2022/23, Appendix Y Network Capability Incentive Parameter Action Plan (https://www.aer.gov.au/system/files/TransGrid-Frontier Economics - Appendix T Return on debt transition letter- R - Z - January 2017.zip)

79 See ElectraNet Revenue Proposal 2019–2023, Attachment 11 Service Target Performance Incentive Scheme (https://www.aer.gov.au/system/files/ElectraNet %E2%80%93 ENET013 %E2%80%93 ElectraNet %E2%80%93 Attachment 11 %E2%80%93 Service Target Performance Incentive Scheme %E2%80%93 March 2017.pdf)

80 Most of these Smart Wires device installations are in Europe and Australia, perhaps because of their regulatory regime. In total, these modular flow controllers have accrued more than 1500 device-years of experience.

81 ERCOT will employ CMPs to facilitate the market use of the ERCOT Transmission Grid, while maintaining system security and reliability in accordance with the Protocols, Operating Guides, and North American Electric Reliability Corporation (NERC) Reliability Standards.

82 Ruiz P. and Caspary, J., SPP Transmission Topology Optimization Pilot—Efficient Congestion Management and Overload Mitigation through Reconfigurations, ESIG Spring Tech Workshop, March 20, 2019.

reconfigurations were used to develop new Operating Guides as reference for use by operators going forward.

While these technologies are gaining momentum, they are far from being widely deployed in a systematic way—most applications in the U.S. are still in the pilot phase. However, these technology options offer significant benefits by enhancing the capabilities of the existing grid. Importantly, when combined with new transmission lines, they can enhance the capability and cost-effectiveness of the investments. This is especially true for those new transmission investments that significantly increase transfer capacity relative to the existing system's transfer capacity. New high-capacity projects tend to have their utilization limited by existing low-capacity lines. By using these technology options to relieve low-capacity lines, new high-capacity lines can be better utilized leading to a stronger benefit/cost ratio. These operational solutions are complementary to transmission investments.

III. Lacking Incentives

As the deployment examples show, these operational technologies, while proven and beneficial, have been used only on a limited scale in the U.S. The slow pace of adoption of these new technology options may largely be driven by two factors. First, the technology options by themselves are not being recognized enough for their capabilities. The underlying view of the industry today generally is that a transmission system has a fixed capacity and topology. Therefore, operational improvements may not be seen as a potential source of operational flexibility and capacity increases. And the newly commercialized technology options to enhance transmission operations are not well understood nor do many operators have much experience with them—in part, because the relevant technologies were still nascent in the early 2000s. Second, there is insufficient incentive[83] for either the transmission operators or owners—the two market players who are best suited to adopt these technologies—to innovate and change their operations, which requires a concerted effort. The inadequate level of incentives could potentially reinforce the first factor.

Why isn't there the needed incentives to deploy these technology solutions to increase operational efficiency and maximize the capability of the transmission grid?

First, transmission operators (*i.e.,* system operators in RTO/ISO markets) are oftentimes indifferent because their performance is not measured strongly against improving operational efficiency, but rather focused on continuously meeting a minimum reliability threshold. The traditional conservative operational process (that assumes a fixed transfer limit and topology) accomplishes this objective. Furthermore, the conservative industry that is responsible for reliability may not provide rewards for enhancing operational efficiently—in fact innovating in operations could be

83 This may be a classic example of the principal-agent problem—*i.e.,* the entity making the decision does not receive the benefit (or cost) of their own action.

considered as taking on unneeded and unwanted risks (and at the extreme putting reliability into jeopardy). Failure of operating new equipment (or software) and concerns over existing equipment (see Entergy's example in the previous section) may be some of the potential risks influencing transmission operators and owners.

Second, many transmission operators and owners today are not impacted by the results (or lack) of operational efficiency, such as a reduction (or increase) in congestion costs. Congestion costs are simply passed through to the other market participants (likely the generators, loads, or intermediaries). The allocation methods of financial transmission rights (either directly by allocating financial transmission rights for certain paths, or indirectly as revenue rights for the financial transmission rights auction proceedings) that favor transmission owners further shields load-serving transmission owners from being directly exposed to congestion-related costs. On the other hand, most of the other market participants (in particular, generators and loads) who do not have the ability to mitigate congestion through actions on the physical system, are exposed to congestion-related costs.

Third, increased operational efficiency of the existing grid could be seen as potentially reducing the need for new transmission investments. For example, the aforementioned DNV GL study points to a reduction of $267 million for transmission expenditure. Transmission owners who earn sufficient returns on investments may prefer larger investments, rather than risking a reduction in such investment return opportunities through operational efficiency. However, these operational technology options do not replace the need for large transmission projects—rather, these technologies are very much complementary to efficient new transmission investments. As discussed before, they can magnify the capabilities provided by and the cost effectiveness of new transmission investments. By using these technologies to relieve constraints in lower voltage low-capacity lines, new high-capacity lines can be better utilized and have a stronger benefit/cost ratio.[84]

Looking at the industry landscape, investment timing is generally becoming shorter. For example, the ISO-NE and PJM forward capacity markets indicate that the electricity industry in general assumes three years to be enough lead time to construct a combustion turbine or combined-cycle plant. [85] Various solicitations from utilities tend to follow a similar timeline. Wind and solar plants

[84] When high voltage lines are added for wind integration purposes (such as for a collector system), the installation of voltage control devices (such as FACTS devices or in some cases through topology control) to prevent over-voltages under low-flow conditions due to contingencies or low wind power availability may become necessary. Further, in the future with higher wind penetration levels, dynamic voltage support will likely become increasingly important, especially if conventional generators are to be displaced in the dispatch order by wind generators. FACTS devices can provide the needed reactive capability.

[85] When the New York Department of Public Service ("NY DPS") assessed the Indian Point nuclear plant retirement contingency plan in 2013 (Indian Point was assumed to potentially retiring in 2016), NY DPS concluded to leave it to market forces to cover the gap. This indicates that NY DPS believed 3 years

can be built even faster, sometimes in less than a year. These fast development timelines did not exist in the mid- to late-20th century when dominant large scale power plants required a longer lead time that was more comparable to the lead time of transmission development. The transmission industry needs to recognize and adjust itself to the change of pace in the industry. Furthermore, the flow patterns observed are generally expected to become more complex and variable as more renewable resources are built and load profiles change with energy efficiency, demand response, distributed energy resources, electrification, and further diversified consumer behavior. The quickly evolving electricity industry can certainly benefit from the operational enhancements to the transmission grid, even if they are used only as a bridge until new transmission lines can be added. Thus, incentives for deploying these lower-cost and shorter-lead-time technologies are needed to support (and potentially to further enhance) transmission expansion as well, as illustrated by the flow control application discussed previously.

Incentives discussed in FERC Order 679 do not adequately address these issues. They tend to focus on new assets and associated investments, and not on operational enhancement, or when and where they should be applied. The large project-specific applications of FERC incentives appear to be biased towards new assets.[86] They are not practical for many of the smaller investments, including the project examples aimed at enhancing grid operations discussed in this white paper. Furthermore, the incentives discussed in Order 679 are based on "risks and challenges." An applicant needs to demonstrate the riskiness of a project and how that risk is creatively mitigated. The operational enhancement projects introduced in this white paper rely on proven technologies that may not be considered risky because of their track record and because of the small size of investments needed for them.

IV. Incentive Policy Options

The inadequate level of incentives provided for operational efficiency technologies in FERC Order 679[87] does not mean there is no precedent for incentives targeted to promote activities beyond

would be enough for the market to respond to the resource shortage that could occur if Indian Point nuclear were to retire.

86 For example, advanced technology project list for an Australia transmission owner ranges in size from $50,000 to $4.9 million. See pages 11-9 to 11-16 of "Final Decision TransGrid transmission determination 2015–16 to 2017–18, Attachment 11–Service target performance incentive scheme" (https://www.aer.gov.au/system/files/AER%20-%20Final%20Decision%20TransGrid%20transmission%20determination%20-%20Attachment%2011%20-%20service%20target%20performance%20incentive%20scheme%20-%20April%202015%20fixed.pdf)

87 As the examples discussed in this white paper demonstrate, the investment costs associated with these operation enhancing technology options are much smaller compared to building new transmission. The significantly larger investment needs naturally guide regulators to focus more on these capital investments to confirm that the large cost is prudent, and less on directing transmission owners towards

investments in new transmission lines. For example, through responses (and the series of workshops) to Order 2000,[88] FERC observed two large patterns of RTO proposals: one with the governance structure centered on a non-profit Independent System Operator; and another on a for-profit Independent Transmission Company ("ITC").[89] There were several proposals[90] for forming ITCs that would act as transmission operators under the umbrella of an RTO.[91] The idea of such ITC-RTO hybrid models at the time triggered discussion on their governance—for example, how to ensure that these for-profit entities can operate independently of other market participants. Such discussions included incentive-based pricing mechanisms to prompt both efficient operations and investment in grid infrastructure.

Other examples of mechanisms to prompt efficient operations include the UK RIIO model (RIIO refers to Revenue = Incentives + Innovation + Output)[92] and the Australian Network Capability Incentive Parameter Action Plan ("NCIPAP") approach. RIIO features an 8-year rate plan and an award-penalty mechanism that incentivizes utilities to identify opportunities to save their end consumers money. The Office of Gas and Electricity Markets ("Ofgem") that regulates the industry sets unit cost allowances ("UCA") for each transmission boundary (or path) in the U.K. The transmission owner can recover the UCA for a given boundary. If the cost of the investment option exceeds the UCA, half of the overage is taken out of the transmission owner's profits and half is paid by the consumers. However, if the cost of the recommended investment option is less than the UCA, the transmission owner keeps half of the savings as additional profit and consumers keep the other half of the savings. Consideration of multiple future scenarios and decisions to take forward investments that provide the most benefit regardless of which future scenario unfolds is a key component of system planning in the U.K. Australia's NCIPAP approach begins with transmission owners who develop a package of technology applications for a defined planning period (currently set for 5 years). Transmission owners are required to consult with the Independent System Operator who conducts independent analysis of network limitations, considering historical congestion, future network flows, and reliability and security implications, and prioritizes options based on reliability and economic value for end consumers. These

increasing operational efficiency, suggesting that Order 679 first addressing investment needs was appropriate.

88 FERC Order 2000, issued December 1999, encouraged the voluntary formation of Regional Transmission Organizations to administer the transmission grid on a regional basis throughout North America.

89 ITC is also referred to as Gridco or Transco.

90 Such proposals include those for forming the American Transmission Company, Entergy Transco, International Transmission Company, TransConnect Transco, and Grid South.

91 The exception is the Grid South proposal.

92 See Ofgem March 2017 "Price controls explained" fact sheet (https://www.ofgem.gov.uk/ofgem-publications/64003/pricecontrolexplainedmarch13web.pdf) and associated websites (https://www.ofgem.gov.uk/network-regulation-riio-model, https://www.ofgem.gov.uk/electricity/transmission-networks/network-price-controls)

investment plans capture all planned network reinforcements. However, small-scale projects are carved out of this broader 5-year revenue allowance. Further these small projects receive a 50% greater return on capital than those larger investments. This incentivizes the utilities to propose small projects that improve network capability, support the wholesale electricity market by reducing network constraints, or benefit end consumers by deferring the need for higher-cost capital projects. While these approaches may not be directly transferrable to the U.S., they provide some useful examples for future directions.

One unique feature of the Australian approach is that the transmission owner is penalized for transmission outages that cause additional congestion. ISO-NE has a similar protocol for scheduling transmission outages. The ISO-NE protocol, aimed for maintaining the reliability of the transmission system while minimizing congestion, allows for ISO-NE to reposition or disapprove any outage that adversely impacts market efficiency. The threshold is $200,000 (or larger) of production cost difference per week (or portion of a week)—*i.e.,* if an outage will increase production costs by more than $200,000 a week, ISO-NE can deny the outage request. ISO-NE reports that this policy has saved end consumers over $210 million since its implementation.[93] Encouraging similar policies among different U.S. markets will help end consumers and provide opportunities for deploying operational enhancement technologies, which will further help the industry, including the end consumers.

As these examples indicate, the key mechanism of "benefit-sharing" (or cost-sharing) between the transmission operator (which could differ from the system operator) and other market participants should be the center of such incentives.

One potential approach is for the FERC to direct the RTO/ISOs to include them in the economic planning processes. The purpose is to allow different transmission technologies to compete by adding an incentive that allows transmission owners to keep a share of the estimated savings (benchmarked against the solution derived through the economic planning process) realized from deploying innovative technology options. This has a similar structure to NYISO's planning process[94] today, where market-based solutions are solicited but the transmission owners are asked to prepare a backstop solution in case the market-based solution is not sufficient. As part of this approach, FERC could establish criteria for what becomes the back stop[95] in the economic studies performed by the RTO/ISOs. The RTO/ISOs could play a role in the evaluation of the different

93 See ISO-NE Operating Procedure No. 3 (https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op3/op3_rto_final.pdf) and the ISO New England Transmission Equipment Outage Coordination 2018 (https://www.iso-ne.com/static-assets/documents/2019/04/2018-iso-ne-transmission-equipment-outage-coordination.pdf)

94 See "Attachment Y—New York ISO Comprehensive System Planning Process" (https://www.nyiso.com/regulatory-viewer)

95 This criteria may be based on "transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities," per Federal Power Act Section 219 (b) 3, added by EPAct.

options while IMMs could play a role in the *ex-post* and on-going evaluation of the program to ensure end consumers are benefitting.

Another approach may be to allow transmission owners to keep a share of the estimated congestion costs savings. A benchmark of anticipated congestion costs can be developed (for example, through the RTO/ISO's economic planning process or historical observations) and the transmission developer earns part of the congestion cost savings (against the benchmark) realized through the new investment. Compared to the first approach that relies largely on the RTO/ISOs planning study process, this second approach allows for a quicker response by market participants.

A bridging approach in the meantime could be to ask the system operators to include these technology options in their transmission planning and operations decision-making processes. Largely triggered by the increase in variable renewable resources, planning studies for generation resources are morphing closer to operational studies that focus on the shorter time horizon—*i.e.,* generation resource planning studies today often take into account granular (in many cases hourly) profiles of load and the variable resources to confirm that the longer-term plan does satisfy shorter-term operational needs. A similar shift could be applied to transmission planning as well, starting with the more immediate "operations planning" timeframe that looks at temporary but potentially costly events that could happen during construction outages,[96] or operational remedies that can be utilized until the longer-term solution is enabled.[97] Inclusion of these technology options will help the system operators and transmission owners better understand these new commercially-available technologies. The combined effect[98] could certainly help system planners to deal with the increasing levels of uncertainty while providing tools to develop an agile system capable of reacting quickly and handling future unknowns. Incentives or guidance will help jumpstart such small changes.

V. Conclusion

The recent advancements in power electronics, communications, computer processing power, and optimization algorithms partially enabled by the increased processing power have led to the development of various new technology options aimed at enhancing the operational efficiency of the transmission grid. Examples of these new technologies include those that explore enhanced and flexible application of the pre-determined transfer capability, represented in this white paper

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96 For example, transmission planning processes today tend to ignore the impacts of both planned and forced transmission outages, which can be significant drivers of congestion costs.

97 Such an assessment may help utilities, especially municipalities, in their budget planning because a large outlay of investment cash may lower their credit ratings, leading to higher borrowing costs.

98 The white paper earlier discussed two driving factors of slow pace of adoption—*i.e.,* that technology options by themselves are not being recognized enough for their capabilities, and that there are insufficient incentives for transmission operators and owners. The incentive policy addresses the second factor while the directive discussed here will help alleviate the first factor.

by DLR and adaptive line rating, and those that focus on flexible and dynamic control of transmission systems, represented in this white paper by flow control devices and topology control software. Compared to major new transmission investments, these technologies can be implemented much faster and often for a small fraction of the cost. Many of these technology options, as examples included in this white paper demonstrate, have been proven to be robust and effective. The economic benefits brought by these operational-efficiency-enhancing technologies have been quantified in a number of studies and applications. Observations from these studies and projects indicate that the benefits of larger-scale deployments can be in the tens to hundreds of million dollars—comparable to the scale of operational benefits provided by the RTO or ISO-operated regional power markets. Importantly, these technology options are complementary to transmission expansion through new lines. They can magnify the cost effectiveness and capabilities provided by new transmission investments. They provide short-term solutions to temporary operational challenges, such as during transmission outages or the construction of new lines, and bridge gaps until permanent expansion solutions can be put in place. The needs for such technologies will likely rise as the pace of industry's transition accelerates.

Transmission operators and owners today have limited incentives for deploying these technologies, and thus end consumers are not enjoying the benefits the technology options can provide. An effective key incentive mechanism may be "benefit-sharing" between the transmission operators (which could differ from the system operator), transmission owners (transmission operators and owners could be different), and other market participants. Insights from the ITC-RTO hybrid proposals (in response to FERC Order 2000), where a separate transmission operator exists under an RTO, or examples from abroad, including those in the U.K. and Australia, may be useful in developing such policies. Other immediate steps that can be taken may include directing the system operators to include these technology options in their transmission planning and operations decision-making processes, which would help the transmission operators and owners better understand these technology options. Just as utilities were able to adjust their operations to integrate large amounts of renewables penetrations within the last decade, they would be able to take advantage of these technologies once the appropriate incentive schemes are in place.

Glossary

AC	Alternating Current
AEP	American Electric Power
CAISO	California Independent System Operator
CMP	Constraint Management Plans
DLR	Dynamic Line Rating
DSR	Distributed Series Reactors
EIM	Energy Imbalance Market
ENTSOI-E	European Network of Transmission System Operators for Electricity
EPAct	Energy Policy Act of 2005
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
FACTS	Flexible Alternating Current Transmission Systems
FERC	Federal Energy Regulatory Commission
IMM	Independent Market Monitor
ISO	Independent System Operator
ISO-NE	ISO New England
ITC	Independent Transmission Company
kV	Kilo-Volt (1,000 volts)
MISO	Midcontinent Independent System Operator
MW	Mega-Watt (1,000 kilo-watts, or 1,000,000 watts)
NCIPAP	Network Capability Incentive Parameter Action Plan
NERC	North American Electric Reliability Corporation
NY DPS	New York Department of Public Service
NYISO	New York Independent System Operator
Ofgem	Office of Gas and Electricity Markets
PAR	Phase Angle Regulators
PG&E	Pacific Gas and Electric Company
RTO	Regional Transmission Operator
SPP	Southwest Power Pool
STATCOM	Static Synchronous Compensator
SVC	Static VAR Compensator
TCSC	Thyristor Controlled Series Capacitors
TLR	Transmission Loading Relief
UCA	Unit Cost Allowances
UPFC	Unified Power Flow Controllers

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