

REGULATORY DIMENSIONS TO RENEWABLE ENERGY FORECASTING, SCHEDULING, AND BALANCING IN INDIA

REGULATORY PRACTICES ANALYSIS AND PRIMER

INDIA ELECTRICITY REGULATORY PARTNERSHIP
Under Greening the Grid (GTG) Program
A Joint Initiative by USAID and Ministry of Power



This publication is made possible by the generous support of the American people through the United States Agency for International Development (USAID). The contents are the responsibility of the National Association of Regulatory Utility Commissioners (NARUC) and do not necessarily reflect the views of USAID or the United States Government

REGULATORY DIMENSIONS TO RENEWABLE ENERGY FORECASTING, SCHEDULING, AND BALANCING IN INDIA: REGULATORY PRACTICES ANALYSIS AND PRIMER

Project Title: India Energy Regulatory Partnership under Greening the Grid Program

Sponsoring USAID Office: USAID/India

Cooperative Agreement #: AID-EEP-A-00-09-0001-00

Implementing Partner: National Association of Regulatory Utility Commissioners (NARUC)

Team: Lakshmi Alagappan and Fredrich Kahrl from Energy and Environmental Economics, Inc;
Rajit Bhavarikar, Regulatory Assistance Program; and
Crissy Godfrey, NARUC

Note: The Primer has been developed under the India Regulatory Partnership under the Greening the Grid Program, a joint initiative between USAID and Ministry of Power. This primer documents the practices followed in India, with specific focus on two states, on RE forecasting, scheduling and balancing of renewable energy and presents practices followed in U.S. with particular focus on the Western United States. The document collates feedback from key stakeholders and is intended to create a fruitful dialogue on how U.S. practices may be relatable to the Indian context. It can be viewed as a working document to support subsequent activities under Greening the Grid, including a guidelines document and pilots. This document is not intended to be an implementation plan.

Contents

1	Forecasting, Scheduling, and Balancing of Renewable Energy: Overview and Regulatory Dimensions	6
1.1	Operational Challenges.....	7
1.2	Regulatory Dimensions	11
2	Forecasting, Scheduling, and Balancing of Renewable Energy in India	14
2.1	Interstate Regulations and Practice.....	14
2.2	Intrastate Regulations and Practice	17
2.2.1	State Model Regulations.....	17
2.2.2	Rajasthan Regulations and Current Practices	18
2.2.3	Tamil Nadu Regulations and Current Practices.....	20
2.3	Priority Areas for Renewable Integration	24
2.3.1	Enabling Economic Dispatch	24
2.3.2	Enabling Greater Regional Coordination	25
2.3.3	Increasing Resource Flexibility.....	26
2.3.4	Clarifying Roles and Responsibilities, and Authority.....	26
3	U.S. Experience with Forecasting, Scheduling, and Balancing of Renewable Energy	28
3.1	Background	28
3.1.1	Ownership, Regulation, and Industry Structure	28
3.1.2	Description of Case Study Areas	31
3.2	U.S. Experience	32
3.2.1	Enabling Economic Dispatch	32
3.2.2	Enabling Greater Regional Coordination	40
3.2.3	Increasing Resource Flexibility.....	49
3.2.4	Clarifying Roles, Responsibilities, and Authority.....	55
4	Priority Areas of U.S. Experience with Relevance for India	60
4.1	Key Insights from the U.S.....	61
4.1.1	Insights and Considerations for Regional Coordination in India.....	61

4.1.2	Insights and Considerations for Integration of Large Scale Renewables in India	62
4.2	Implementation Considerations, Using Illustrative Example of Joint Dispatch	63
4.3	Design Considerations	66
Area	66
5	References	67
6	Appendix: Background on India’s Electricity Sector, Renewable Energy Goals, and Interstate Regulations	72
6.1	Organization of India’s Electricity Sector	72
6.2	Renewable Energy Development in India	74
6.3	Interstate Regulations for Forecasting, Scheduling, and Balancing of Renewable Energy	77
6.3.1	Framework for Renewable Generation	77
6.3.2	Framework for Non-Renewable Resources	80
6.4	State Model Regulations.....	84

Acknowledgements

The purpose of this report is to understand the regulatory dimensions to renewable energy forecasting, scheduling, and balancing in India's power grid. This work is conducted under United States Agency for International Development (USAID)'s Greening the Grid program, which is a multi-year initiative implemented in partnership with Ministry of Power, Government of India.

We thank the multiple stakeholders that generously gave their time towards the field interviews conducted as part of this study, including Ms. Shubha Sarma and Dr. S. Chatterjee of the Central Electricity Regulatory Commission; Mr. S.K. Soonee, Mr. K.V.S. Baba and their colleagues from POSOCO; Mr. Pankaj Batra of Central Electricity Authority; Ms. Auxiliam Jayamary, Director (Operations), and her colleagues from TN SLDC, and Mr. Akshaya Kumar, Chairperson, and his colleagues from TNERC; Mr. V. Hiremath, Chairperson, and his colleagues at RERC; Mr. Sanjay Mathur and his colleagues from Rajasthan SLDC; Mr. Banna Lal, Managing Director and his colleagues at RUVNL; Mr. B.B. Mehta, Chief Engineer of Gujarat State Load Dispatch Center; and numerous other stakeholders. We also acknowledge the active participation of Dr. S. Chatterjee of the Central Electricity Regulatory Authority and Mr. S.K. Soonee of POSOCO for providing written comments on earlier drafts of this report. Lastly, we thank Ms. Jyoti Arora, Joint Secretary, Ministry of Power for providing active leadership on Greening the Grid and for leading the Indian delegation to the U.S. that helped shape the primer.

Regulatory Dimensions to Renewable Energy Forecasting, Scheduling, and Balancing in India

Forecasting, scheduling, and balancing are *the* foundation for higher penetration renewable electricity systems. Together, they constitute the core processes through which variable renewable generation — wind, solar, and run-of-river hydroelectric — is transmitted over the electricity grid and delivered to consumers. Although forecasting, scheduling, and balancing are often thought to be largely within the sphere of electricity system operations, they also have important regulatory dimensions.

In India, rapid growth in renewable electricity generation has required the recent development of regulatory frameworks that govern renewable energy forecasting, scheduling, and balancing. These frameworks will need to continue to evolve to meet emerging challenges associated with meeting India's 2022 renewable energy goals.¹

Many emerging regulatory challenges in India have parallels in the United States, due, in part, to the federalist tradition in both countries. U.S. experience in integrating renewable energy could provide valuable insights for India, and vice versa.

This primer provides a U.S. perspective on priority areas for improving the forecasting, scheduling, and balancing of renewable energy in India.² Based on a review of regulatory documents and practices, it identifies four priority areas:

- ***Enabling economic dispatch*** — policy and regulatory frameworks that enable least-cost dispatch of all generation, including variable renewable generation, as a strategy for economically managing renewable energy curtailment;
- ***Enabling greater regional coordination*** — open access regulations and cooperative arrangements that reduce barriers to trade in renewable generation among states and enable greater coordination in dispatch among states;
- ***Increasing resource flexibility*** — new incentive designs that increase the flexibility of coal generation units and loads;
- ***Clarifying roles, responsibilities, and authority*** — allocation of roles, responsibilities, and authority in India's evolving national electricity system.

¹ This primer focuses on the subset of renewable energy development questions related to grid integration and power system operations. For a discussion of issues associated with overall policy support, incentive design, project finance and development, and power system planning, see MoP (2016), NITI Aayog et al. (2015), GIZ-India (2015).

² The primer focuses on the high voltage ("bulk") transmission system; it does not cover integration challenges at the distribution system level.

In each of these four areas, the primer describes key elements of U.S. regulatory experience that may be relevant for the transition to higher penetrations of renewable energy in India. It seeks to provide a reference on potential nearer- and longer-term solutions to emerging challenges for a regulatory audience in India.

The primer is organized into four sections.

- ***Forecasting, Scheduling, and Balancing of Renewable Energy: Overview and Regulatory Dimensions*** provides a brief overview of the operational challenges created by variable renewable generation. It examines the intersection between these operational challenges and the regulatory questions they present, such as open access to the grid and regional coordination in operations.
- ***Forecasting, Scheduling, and Balancing of Renewable Energy in India*** examines evolving regulatory frameworks for forecasting, scheduling, and balancing renewable energy in India, both at a central government (interstate) level and at a state (intrastate) level in Rajasthan and Tamil Nadu. Drawing on a review of regulatory documents and discussions and interviews,³ it identifies key successes thus far and emerging areas of challenges to renewable energy integration in India.
- ***U.S. Experience with Forecasting, Scheduling, and Balancing of Renewable Energy*** describes lessons from U.S. experience in each emerging challenge area that could be relevant for India, drawing on case studies from California, Colorado, and Oregon.
- ***Priority Areas of U.S. Experience with Relevance for India*** identifies areas of U.S. experience that are particularly relevant to an Indian context, describes why and how they are relevant, and identifies areas to explore in further detail. This section will be completed in early 2017.

An Appendix provides background on the organization of India's electricity sector, renewable energy goals, and a more detailed description of interstate and intrastate regulatory documents.

1 Forecasting, Scheduling, and Balancing of Renewable Energy: Overview and Regulatory Dimensions

Forecasting, scheduling, and balancing form the core of grid operations — how the electric grid is operated to ensure that electricity supply and demand remain constantly in balance. By shaping how renewable generators are integrated into grid operations, these three processes are critical in determining whether renewable generation can be integrated reliably and at low cost. Additionally, by

³ The section on intrastate regulations is based on conversations with electricity system regulators and operators in both Rajasthan and Tamil Nadu through an intensive week-long study tour in August 2016. We would like to thank those that we spoke with at the Rajasthan Electricity Regulatory Commission (RERC), Rajasthan State Load Dispatch Center (RSLDC), Rajasthan Discoms Power Procurement Center (RDPPC), Tamil Nadu Electricity Regulatory Commission (TNERC), Tamil Nadu State Load Dispatch Center (TNSLDC), Tamil Nadu Electricity Board (TNEB), and National Institute of Wind Energy (NIWE) for their time and continued effort in helping to shape this primer.

determining revenues and costs to renewable generators, they influence the financing of renewable energy projects and thus shape the future development of renewable energy resources.

This section provides an overview of the challenges that renewable generation creates for grid operations, as well as the regulatory dimensions to these challenges. The discussion in this section provides a general framework for the rest of the primer.

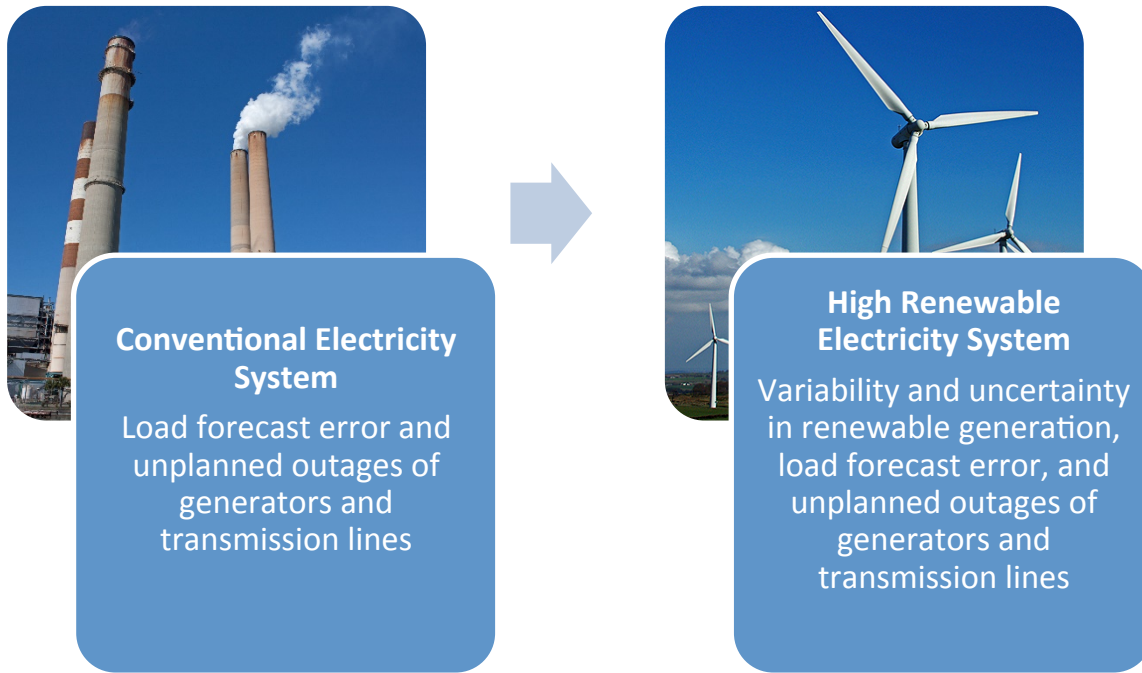
1.1 Operational Challenges

Historically, the main challenge to maintaining constant balance between electricity supply and demand in all power systems was the inherent variability and uncertainty in demand and the unplanned outage of generators and transmission equipment. To address this challenge, grid operators scheduled generation and transmission capacity to meet the next day's forecasted demand and either held additional generation capacity in reserve to "follow" changes in demand and mitigate potential shortfalls in supply, or disrupted service to ("curtailed") customers when demand exceeded supply.

Rising penetrations of renewable generation — and in particular solar and wind generation — in some electricity systems are creating new challenges for system operators, even as "traditional" challenges remain (Figure 1). The operating challenges created by these resources are increasingly well understood. Solar and wind generation more closely resemble electricity demand than conventional thermal, hydropower, or nuclear generation. Like demand, solar and wind resources are inherently variable and uncertain, and forecasts of their output improve significantly closer to real-time. Aggregating solar and wind resources over larger geographic areas tends to reduce both their variability and forecast error.⁴

⁴ For more on the benefits of a larger geographic area for balancing solar and wind variability and uncertainty, see Parsons et al. (2006), Milligan and Kirby (2007), GE Energy (2010), Milligan et al. (2010), EnerNex Corporation (2011), and Mai et al. (2012).

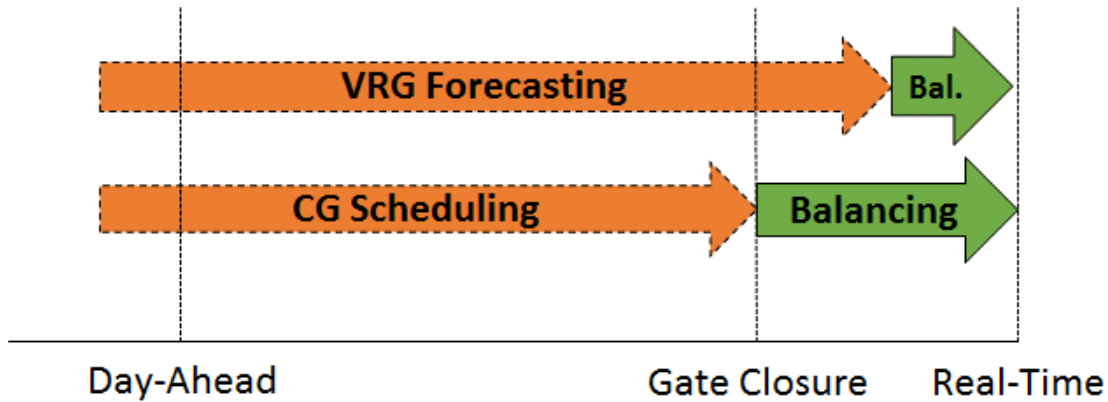
Figure 1. Operating Challenges for Conventional and High Renewable Electricity Systems



To better integrate solar and wind generation into grid operations, many grid operators have established solar and wind forecasts and have begun to integrate them into their overall process of scheduling and dispatching generators to meet electricity demand. In practice, integrating solar and wind generation onto the grid has meant using thermal and hydroelectric resources to balance the variability and uncertainty in net load — load minus wind, solar, and run-of-river hydropower.

The distinction between scheduling and balancing is often ambiguous and context specific. In this primer, we define 'scheduling' as the process of arranging and rearranging generators to meet forecasted electricity demand, and 'balancing' as the process of re-dispatching generators once schedules are considered fixed. For conventional generators, this fixing of schedules typically corresponds to gate closure in intraday markets. For variable renewable generation — wind, solar, and run-of-river hydropower — forecasts are used to set schedules. Forecasts often extend across gate closure (Figure 2).

Figure 2. Illustration of the Timescales of Forecasting, Scheduling, and Balancing of Variable Renewable Generation (VRG) and Conventional Generation (CG)

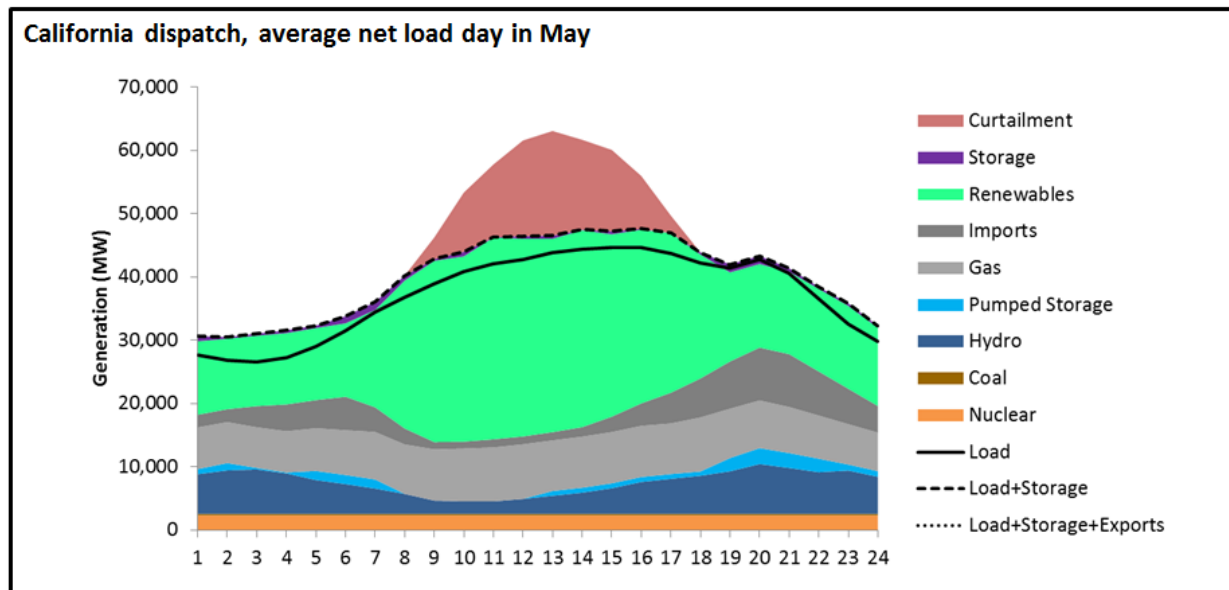


In engineering-economic terms, economic (merit order) dispatch of variable renewable generation implies that system operators will dispatch its available generation whenever possible, because it has very low marginal costs. From a societal perspective, economic dispatch of variable renewable generation will minimize total electricity system costs and maximize the societal value of these resources.

In practice, rising penetrations of variable renewable generation will begin to create local and system-wide grid congestion — in this case, when generator schedules exceed local demand plus export capability⁵ — on days with high solar or wind generation and low demand or if generator schedules are too rigid. As with conventional congestion, when faced with this situation system operators will need to curtail generator schedules to avoid overgeneration conditions (Figure 3). Regulators and system operators are increasingly exploring economic approaches to managing renewable energy-related congestion, in ways that minimize costs to customers and provide value to producers.

⁵ Technically, a more precise definition of congestion is when requested generator schedules exceed available transfer capability over a given path, but these definitions are equivalent in this case.

Figure 3. Forecasted Curtailment of Renewable Energy on a High Renewable, Low Load Day in California in 2030 (50% Renewable Penetration, Status Quo Operating Paradigm)⁶



Some amount of curtailment, or “dispatch,” of variable renewable generation is likely to be economically efficient. Increasingly, interconnection standards for variable renewable generators have higher requirements for dispatchability and provision of ancillary services. However, high levels of curtailment are unlikely to be efficient and will discourage renewable generation investment.

Approaches to determining economic levels of variable renewable generation curtailment vary across electricity systems and regulatory contexts. To the extent that curtailment is uneconomic, or is undesirable from a public policy perspective, there are generally two approaches to reducing it:

- 1) Increase the flexibility of the existing electricity system, through:
 - Changes in grid codes, operating processes, dispatch time intervals, regulations, and market designs;
 - Encouraging portfolio diversity in renewable resources (wind, solar, hydropower, geothermal) and spatial diversity in the location of renewable resources;
 - Changes in pricing that encourage consumption during periods of high renewable generation;
 - Expanding balancing areas.

- 2) Invest in new resources that increase electricity system flexibility, including:
 - Demand response technologies;
 - Energy storage;

⁶ “Status quo operating paradigm” here refers to the California Independent System Operator as a single-state balancing authority using pre-existing market rules and expectations for minimum thermal generation levels. Figure is from E3 (2016).

- New transmission;
- New flexible generation.

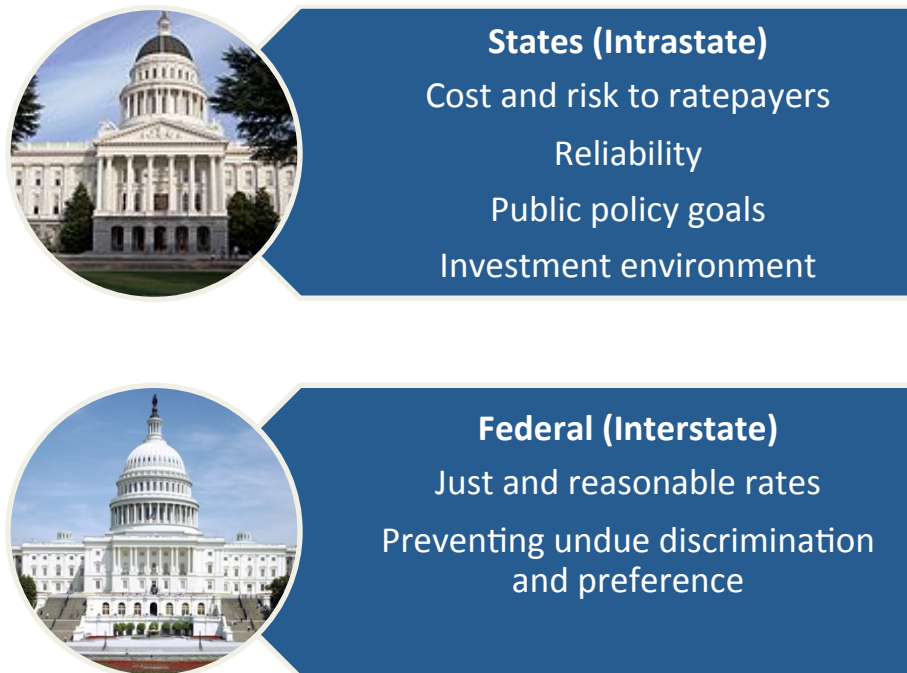
Among these options, increasing the flexibility of the existing electricity system through changes in forecasting, scheduling, and balancing processes tends to be less expensive than investing in new resources. In most cases, however, these changes require an enabling regulatory framework and the need to deal with a more complex set of political economy and institutional challenges.

1.2 Regulatory Dimensions

Regulatory questions around the forecasting, scheduling, and balancing of renewable energy concern the allocation of benefits, costs, and risks along the electricity supply chain — among independent generators, between independent generators and load serving entities (LSEs), and between LSEs and customers. Although these allocation questions focus on the short-run operation of the power system, they have important implications for longer-term contracts and procurement and investment decisions.

The metrics that regulators use to evaluate regulatory design and regulatory change often differ across countries and between different levels of government. In this primer, we take a U.S. perspective on evaluative metrics, combining state and federal metrics (Figure 4). That is, changes in regulation to support integration of renewable energy are beneficial if they increase the chance of meeting renewable energy goals, increase or maintain reliability, reduce costs and risks for customers, are fair and reasoned, and create a supporting investment environment. We use this perspective to identify emerging challenges in the Indian context in Section 2, and in describing U.S. experience in Section 3.

Figure 4. Key Metrics used by U.S. State and Federal Electricity Regulators for Evaluating Regulatory Design and Change⁷



Increasingly diverse ownership of renewable generation complicates the regulatory questions associated with forecasting, scheduling, and balancing of renewable energy. In many countries, including India, the U.S., and parts of Europe, renewable generation is primarily owned by independent power producers. This can create conflicts with incumbent utilities and raises questions over how to ensure fair and non-discriminatory access to the grid for these producers. For instance, system operators may curtail renewable generation in ways that are consistent with utility incentives or existing contractual arrangements but are not societally beneficial. Creating the institutions to encourage societally economic curtailment of renewable energy is principally a regulatory problem.

In the context of more diverse generation ownership, the regulator’s task is to address stakeholder concerns and reconcile competing interests in four areas (Table 1): (1) the allocation of forecasting costs and forecast error penalties for renewable generation; (2) operating costs for conventional generation; (3) investment costs and contracts for generation and transmission; and (4) changes in costs that result from greater coordination among balancing areas.

⁷ “Rates” in the U.S. refers to tariffs and prices. This characterization does not explicitly include the perspective of environmental regulators.

Table 1. Different Stakeholders’ Cost and Risk Concerns

	Renewable generators	Thermal generators	Hydro generators	Utility or LSE	Customer
Forecasting	Forecast error penalty, forecasting costs				Higher prices
Operating		Cycling and ramping costs			Higher prices, reliability
Investment	Curtailment costs**	Declining utilization, lower prices, opportunity costs*	Opportunity costs*	Contract risk, obligations***	Higher prices
Regional coordination		Declining utilization		Contract risk, Obligations***	Higher prices, reliability

* *Opportunity cost refers to the cost of missing high market price hours or of having to replace lower cost generation with more expensive generation.*

** *Curtailment costs for renewable generators includes the opportunity cost of curtailment related to overgeneration and provision of “essential reliability services” (ramping capability, frequency control, voltage control).⁸*

*** *Obligations here refers to regulatory requirements to install or procure renewable generation.*

Renewable generators seek to balance forecast error penalties and forecasting costs, while reducing curtailment. Thermal generators, or their utility owners, typically require incentives to operate more flexibly, and may be concerned with declining plant utilization. Utilities and LSEs may be concerned over potential contract risks with renewable and non-renewable generators, and their ability to meet regulatory obligations for renewable energy if renewable generation faces high curtailment. Customers will be concerned over potential price increases and potential decreases in reliability. Greater coordination across balancing areas may improve policy outcomes for renewable energy deployment, but may have distributional impacts.

Reconciling these concerns requires finding ways to:

- discover economic levels of renewable energy curtailment;
- align utility and LSE incentives with renewable energy goals;
- reasonably compensate thermal generators for cycling and ramping costs and lower utilization, such as through wholesale market prices or on a cost basis; and
- minimize price impacts or even reduce prices for all customers.

⁸ This categorization is from NERC (2015). For more on using renewable energy to provide these services, see Loutan (2016).

In higher penetration renewable electricity systems, the essential balance that regulators must try to find is between: (1) curtailment of variable renewable generation and the contractual and market risks that it creates for renewable generation, on the one hand; and (2) increases in electricity system costs that result from reducing variable renewable generation curtailment, on the other. In striking this balance, regulatory changes to improve forecasting, scheduling, and balancing are a low hanging fruit, and may even pay dividends by addressing other inefficiencies and reducing system costs.

2 Forecasting, Scheduling, and Balancing of Renewable Energy in India

Regulatory frameworks and practices for forecasting, scheduling, and balancing of renewable energy in India have evolved significantly over the past five years. This section describes current regulations and practice at an interstate level and at an intrastate level in Rajasthan and Tamil Nadu. Based on these accounts, it then assesses successes thus far and priority challenge areas going forward.

2.1 Interstate Regulations and Practice

This section provides a brief overview of four regulatory documents that comprise the core interstate regulatory framework affecting renewable energy integration. These four documents include:

- *Framework on Forecasting, Scheduling and Imbalance Handling for Variable Renewable Energy Sources;*
- *Deviation Settlement Mechanism and Related Matters;*
- *Ancillary Services Operations Regulation;* and
- *Open Access in Inter-state Transmission Regulations.*

A more detailed description of these documents is provided in the Appendix.

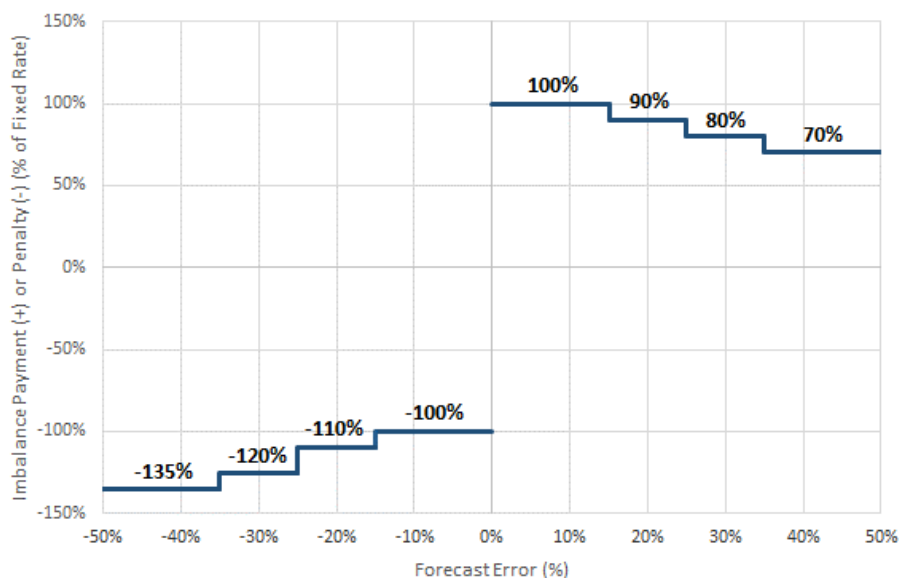
Framework on Forecasting, Scheduling and Imbalance Handling for Variable Renewable Energy Sources. The Central Electricity Regulatory Commission (CERC) finalized the *Framework on Forecasting, Scheduling and Imbalance Handling for Variable Renewable Energy Sources* (“*Framework*”) in August 2015, as a successor to the proposed Renewable Regulatory Fund (RRF). The *Framework* created a forecasting and scheduling procedure for wind and solar generation and a system of imbalance charges for interstate renewable generators.

Specifically, the *Framework* requires interstate wind and solar generators to submit forecasted schedules for the following day, or accept a default forecast by the Regional Load Dispatch Center (RLDC). On the day of, generators are allowed to revise their schedules up to 16 times, with each revision corresponding to a one-and-a-half-hour time block and revisions taking effect one hour (4 time blocks) after they are made. Generators are paid their power purchase agreement (PPA) price for scheduled generation, and pay an imbalance charge for deviations from schedule. Deviation charges are tiered for absolute forecast errors that exceed 15% of available capacity, and are asymmetric, with higher charges for under-forecasts (Figure 5).

Under the *Framework*, renewable energy credits (RECs) to meet state renewable purchase obligations (RPOs) are allocated based on scheduled rather than actual generation. The REC implications of differences between scheduled and actual renewable energy generation are managed by the National

Load Dispatch Center (NLDC), which sells and purchases RECs through its imbalance pool to ensure that interstate RECs match actual interstate renewable generation.

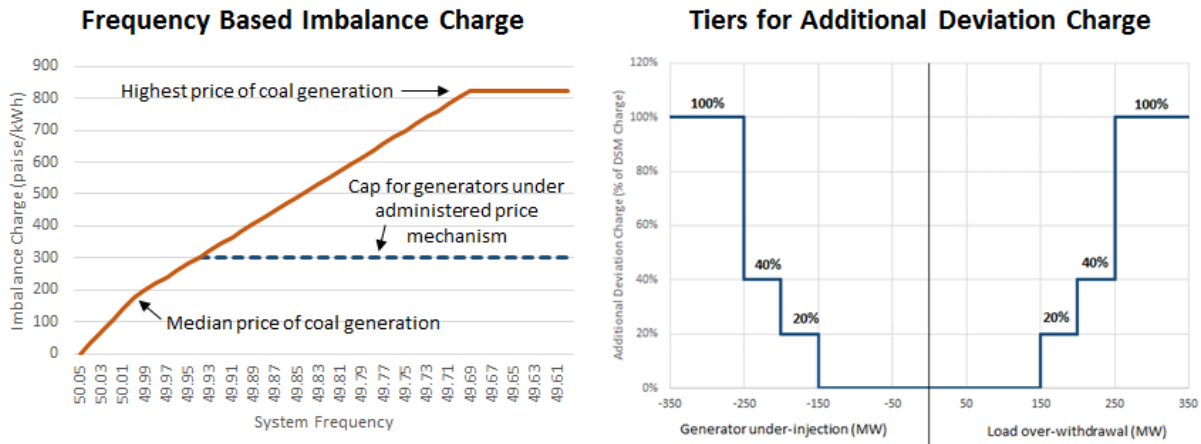
Figure 5. Tiered Imbalance Charges (Payments and Penalties) for Wind and Solar Generators under the Framework



Deviation Settlement Mechanism and Related Matters. The deviation settlement mechanism (DSM) grew out of and replaced the availability based tariff’s (ABT’s) unscheduled interchange (UI) mechanism in 2014. Under the DSM, load serving entities are charged for deviations from requested day-ahead schedules for interstate generation, and interstate generators (excluding wind and solar) are charged for deviations from committed day-ahead schedules. Because the scheduling and balancing of non-renewable generation affects the balancing of renewable energy, the DSM is relevant to the discussion in this primer.

The DSM uses a two-part structure, with a frequency-based imbalance charge based on proxy incremental energy costs and a tiered additional deviation charge based on over-withdrawals (loads) or under-injections (generators) that exceed 150 MW or 12% of schedule, whichever is lower (Figure 6). DSM charges on over-withdrawals may be only indirectly tied to interstate generation schedules — the interstate system effectively acts as a national balancing mechanism for any state imbalances.

Figure 6. Frequency-Based Imbalance Charge and Tiers for Additional Deviation Charge under the DSM⁹



Thresholds for additional deviation charges (“DSM limits”) — the maximum limit before penalties begin to be imposed — effectively act as an intraday import limit on states. In 2016, CERC loosened these limits for renewable rich states until April 2017. States with 1,000 MW to 3,000 MW of solar and wind capacity are allowed a DSM limit of 200 MW; states with greater than 3,000 MW of solar and wind capacity are allowed a limit of 250 MW.¹⁰

Ancillary Services Operations Regulation. Before 2016, the DSM functioned as a decentralized mechanism to address interstate load-generation imbalances on all timescales. CERC’s 2016 *Ancillary Services Operations Regulation* provides a framework for the NLDC to centrally dispatch interstate generating units through the RLDCs for the purpose of maintaining grid frequency. The framework also includes a mechanism to compensate interstate generators for providing this service. In practice, the NLDC creates a merit order stack (based on variable cost) of interstate generating units that have capability to provide ancillary services in either the upward or downward direction. The units are called upon for ancillary service dispatch when there are system triggers, such as extreme weather, generator or line outages, or increasing area control error. To ensure units are not penalized for deviating from their day ahead schedules, units that are dispatched for ancillary services are only assessed for DSM for deviations on their day ahead schedules adjusted by their ancillary service schedules.

Open Access in Inter-state Transmission Regulations. CERC’s 2004 *Open Access* regulations govern access to the bulk transmission system for independent generators and direct access customers. The regulations created, inter alia, a reservation system for short-term (less than 1 year) and long-term (greater than 25 years) transmission customers, an auction mechanism for allocating capacity in the event that requests for short-term transmission capacity exceed available capacity, and a system of curtailment priority where long-term transmission customers have priority over short-term customers

⁹ The price points and tiers are explained in greater detail in the Appendix.

¹⁰ States argued that these looser limits were needed to address higher renewable energy penetrations, though a POSOCO study indicated deviations were primarily resulting from load forecast error, rather than renewable energy. CERC (2016).

within each service class and are curtailed on a pro rata basis during congestion events. In 2016, CERC exempted interstate wind and solar generators from transmission access and loss charges.¹¹

2.2 Intrastate Regulations and Practice

This section describes the intrastate regulatory framework for forecasting, scheduling, and balancing renewable energy, with a focus on two states: Rajasthan and Tamil Nadu. These two states ranked second and first, respectively, among Indian states in terms of installed renewable generation capacity in early 2016.¹² They are also among the first states to create regulatory frameworks for forecasting, scheduling, and balancing.

Many states, including Rajasthan and Tamil Nadu, are still in the process of translating these frameworks into practice. Thus, this section also describes current forecasting, scheduling, and balancing practices in Rajasthan and Tamil Nadu. The examination of current practices in this section is based on discussions and interviews in August 2016.

2.2.1 State Model Regulations

Following on CERC's *Framework*, the Forum of Indian Regulators (FOR) issued *Model Regulations on Forecasting, Scheduling and Deviation Settlement of Wind and Solar Generating Stations at the State Level* ("FOR Model Regulations") in 2015.¹³ The FOR's *Model Regulations* closely mirror CERC's *Framework*, with four key differences:

- 1) Stipulations for a week-ahead forecast in addition to the day-ahead forecast;
- 2) Payment settlement based on actual generation, rather than scheduled generation, for intrastate sales;
- 3) The introduction of qualified coordinating agencies (QCAs) as an aggregator for solar and wind forecasting and settlement; and
- 4) Tightening of the deviation bands from 15% (in the *Framework*) to 10% for new generators.

Though not explicitly stated, the addition of the week-ahead wind and solar forecasting is likely to help inform thermal unit commitment (startup/shutdown) decisions for the SLDCs, as coal units in particular may have unit commitment horizons that exceed a day-ahead timeframe. The settlement system for wind and solar generation — based on actual rather than scheduled generation — retains existing intrastate settlement practices, rather than harmonizing these with the central-level *Framework*.

From an administrative perspective, this lack of harmonization between interstate and intrastate regulations does not currently appear to be an issue, as most wind and solar generators are interconnected at the state level and sell to entities within that state. However, it could prove problematic if generators wish to sell at both the intrastate and interstate level. For instance, Suzlon indicated that it currently has to interconnect individual turbines on two separate feeders, depending on

¹¹ Heeter et al. (2016).

¹² Data are from MoP and CEA (2016)

¹³ FOR (2015).

if it is delivering to intrastate or interstate systems, to deal with separate accounting systems for payment and deviation under state and central regulations.¹⁴

To better harmonize intrastate regulations for scheduling and settlement, FOR facilitated a *Report on Scheduling, Accounting, Metering, and Settlement of Transactions in Electricity (SAMAST)* in July 2016, which sought to consolidate existing experience and provide recommendations for the creation of an interoperable system of scheduling, energy accounting, energy metering, and transaction settlement across state boundaries.¹⁵

2.2.2 Rajasthan Regulations and Current Practices

Rajasthan falls under the Northern RLDC’s jurisdiction, although it shares borders and trade agreements with states in the Western RLDC. Table 2 lists key agencies within Rajasthan that are involved in the design and implementation of regulations for forecasting, scheduling, and balancing of renewable energy.

Table 2. Key Agencies in Rajasthan with Responsibility for Forecasting, Scheduling, and Balancing¹⁶

Organization		Role	Responsibilities
Rajasthan Electricity Regulatory Commission	RERC	SERC	Issues and enforces electricity regulations
Rajasthan Rajya Vidyut Prasaran Nigam	RVPN	STU	Plans, builds, owns, and operates state-owned generation and the intrastate transmission system
Rajasthan State Load Dispatch Center	RSLDC	SLDC	Subsidiary of RVPN, oversees intrastate grid security
Rajasthan Rajya Vidyut Utpadan Nigam Limited ¹⁷	RUVN	Discom coordinator	Procures resources on behalf of, and schedules resources for, Rajasthan’s five discoms ¹⁸

2.2.2.1 Regulations

RERC released draft forecasting, scheduling, and balancing regulations for wind and solar generators (“*RERC Regulations*”) in March 2016.¹⁹ The regulations mirror the FOR’s *Model Regulations* closely, but have three key differences. First, the regulation is only applicable to wind and solar generators that have

¹⁴ Based on interviews with Suzlon staff.

¹⁵ FOR (2016).

¹⁶ SERC in the below table refers to “state electricity regulatory commission”; STU refers to “state transmission utility.”

¹⁷ RUVN was formerly known as the Rajasthan Discoms Power Procurement Center (RDPPC).

¹⁸ These five discoms include: Rajasthan Vidyut Utpadan Nigam, Jaipur Vidyut Vitran Nigam, Ajmer Vidyut Vitran Nigam, Rajasthan Rajya Vidyut Prasaran Nigam, and Jodhpur Vidyut Vitran Nigam.

¹⁹ RERC (2016).

a minimum installed capacity of 5 MW, either individually or through a pooling station. The RERC believed that for capacities less than 5 MW it was very difficult to have “visibility and monitoring at the level of the SLDC,” and specifically cited rooftop solar projects as the kinds of projects it intended to exclude from coverage under the regulation.

Second, the regulations are immediately applicable to all new wind and solar facilities. The RERC expects new wind and solar facilities to establish forecasting arrangements prior to the commissioning of the plant and interconnection to the state grid. Existing facilities have three months to establish forecasting compliance. And third, the deviation settlement tolerance band was set to the 15% tolerance band as in the CERC *Framework*, rather than the tighter 10% tolerance band in the FOR’s *Model Regulations*. The *RERC Regulations* noted that the CERC tolerance band was a “reasonable limit to start with” and appreciated the mechanism’s simplicity to implement and minimal financial impact on existing PPAs. RERC has not finalized the regulations to date, but indicated in conversations that it plans to do so soon.

In addition to the draft *RERC Regulations*, RERC also notified the intrastate ABT in 2006, but has been unable to enforce it due to lack of the necessary metering infrastructure. The intrastate ABT in Rajasthan would implement the same structure as the interstate ABT. It includes fixed cost, variable cost, and imbalance charge components. Many of the parties we interviewed in Rajasthan believed that the implementation of this intrastate ABT is imperative to being able to fully integrate the large amounts of renewables coming online in the state because it would force the proper metering and software that would enable better system dispatch.

2.2.2.2 *Current Practices*

The study team met with representatives from the RERC, RSLDC, and RDPPC to better understand system operations and practices. This section provides a summary of those conversations, with a focus on current forecasting, scheduling, and balancing practices.

Even though the *RERC Regulations* have not been finalized, the RDPPC is currently receiving day wind ahead forecasts at the pooling station level from IWTMA by 10 am. NIWE suggested that REConnect and Manikaram are both providing forecasts for wind generators in Rajasthan, even though there are only a few wind plants in place. RDPPC is doing its own forecasting as well, based on the wind speed forecasts from Underground Weather. This forecast is then used to adjust the vendor forecast. In practice, RDPPC stated that the forecast is close to actual generation during the high wind season.

Although intraday forecast revisions are provided by wind generators, as allowed in the *RERC Regulations*, RDPPC and the RSLDC did not think these revisions were useful in being able to utilize intraday balancing mechanisms, such as the power exchange, because market procurement decisions are made on a day-ahead timescale. Currently, the RDPPC looks at the market clearing price from the power exchange at 12 pm on the previous day and checks the day-ahead renewable forecasts and expected thermal generation. If RDPPC has excess scheduled capacity, it decides whether to sell to the exchange or back down plants under its control, based on the exchange price. If it has insufficient scheduled capacity, it decides whether to buy from the exchange or turn up generators. RDPPC indicated intraday prices from the power exchange are also expensive and not economical. However,

RDPPC did note that intraday revisions to schedules could help with intraday scheduling and dispatch of interstate and intrastate generators.

RDPPC also indicated that week-ahead forecasts from renewable generators would be very helpful to RDPPC and RSLDC for understanding when they could turn off thermal facilities, as they require a longer time horizon for commitment decisions than on a day-ahead basis. This is likely a short-term issue until the regulation is finalized, given that the draft *RERC Regulations* require week-ahead schedules.

For purposes of scheduling, renewables are treated as a must-run resource in Rajasthan and their forecasts act as their schedules. Scheduling and dispatch of the rest of the system is meant to be conducted on a merit order basis, with units being dispatched in variable cost order. The RDPPC and RSLDC indicated that the variable costs for the merit order dispatch are updated annually via tariff updates.

Once generator schedules are set, the balancing of load and generation occurs on an intraday basis by RDPPC. In the case where renewables are over-generating relative to forecast (or load is under-forecasted), RDPPC backs down state generators first to account for the imbalance.²⁰

To account for established seasonal cycles of oversupply and deficit, Rajasthan has entered into power exchange agreements with neighboring states through firm banking transactions. These agreements can last from 15 days to a month at a time and are often put into place for multiple times in a season. For example, Rajasthan sends power to Punjab and Haryana from April to September when Rajasthan has surplus power, and imports from Punjab from October to March when Rajasthan is in deficit.

RDPPC has also encouraged the sharing of renewable resources with other states, as Rajasthan is a renewable rich state, but noted that the existing DSM hindered these types of transactions. Currently, a wind generator in Rajasthan contracted to export half of its energy to Punjab would face a deviation charge based on its full generation rather than its generation for export, for which the deviations of the full output counts against Rajasthan’s DSM limits. This is an issue now because forecasting has not been completely implemented, and RDPPC noted that this problem goes away when there is better forecasting.

2.2.3 Tamil Nadu Regulations and Current Practices

Tamil Nadu is part of the Southern RLDC. lists key agencies within Tamil Nadu that are involved in the design and implementation of regulations for forecasting, scheduling, and balancing of renewable energy.

Table 3. Key Agencies in Tamil Nadu with Responsibility for Forecasting, Scheduling, and Balancing

Organization		Role	Responsibilities
Tamil Nadu Electricity	TNERC	SERC	Issues and enforces electricity regulations

²⁰ This practice may be used to minimize DSM penalties, as schedule deviations for non-renewable generators under the DSM are calculated on a day-ahead basis.

Regulatory Commission			
Tamil Nadu Transmission Corporation	TANTRANSCO	STU	Plans, builds, owns, and operates the intrastate transmission system
Tamil Nadu State Load Dispatch Center	TNSLDC	SLDC	Subsidiary of TANTRANSCO, operates the intrastate transmission system
Tamil Nadu Generation and Distribution Corporation	TANGEDCO	Discom	Owns and operates generation, owns and operates distribution system, serves load
Tamil Nadu Electricity Board	TNEB	Holding company	Holding company for TANTRANSCO and TANGEDCO

2.2.3.1 *Regulations*

Similar to Rajasthan, Tamil Nadu issued draft forecasting, scheduling, and balancing regulations (“*TNERC Regulations*”) in February 2016.²¹ These draft regulations are most closely modeled after the FOR’s *Model Regulations* and are applicable to all wind and solar generators connected to the state grid, including those connected via pooling stations and those that may be below 5 MW (unlike in Rajasthan). A key difference between the Tamil Nadu draft regulations and other regulations discussed in this primer is Tamil Nadu’s treatment of the DSM. Tamil Nadu included the more restrictive deviation tolerance band for wind facilities (10%) and created a separate deviation mechanism for solar facilities with a tighter deviation tolerance band (5%). A new set of draft regulations was released by TNERC for comment while this primer was being prepared, which would replace the draft regulations described above if adopted. The new draft regulation entitled “*Model DSM Regulations at State Level*” harmonizes Tamil Nadu’s treatment of both thermal and renewable deviations with CERC’s so that thermal deviations follow DSM and renewable deviations follow the *Framework*.

In addition, TNERC has notified the intrastate ABT, but the ABT has yet to be implemented because the relevant metering infrastructure and software is still under procurement. TNSLDC was still in the procurement process in August 2016 and TNERC said that optimistically it would take 12 months to implement once the infrastructure was in place.

2.2.3.2 *Current Practices*

This section explores the current practices for forecasting, scheduling, and balancing in Tamil Nadu.

Tamil Nadu was the first state to undertake forecasting for wind generators in India through an Indo-Spanish collaborative forecasting pilot between the National Institute of Wind Energy (NIWE), based in Chennai, and Vortex, a Spanish forecasting company. The pilot started with several 50 MW wind farms. The goal was to create a business model for forecasting in India. The success of the pilot has brought the

²¹ TNERC (2016).

majority of wind in Tamil Nadu under forecasting. A forecast is provided for every substation and there are plans to provide forecasts at the turbine level as well. Wind generators are paying for the forecasting service and the Indian Wind Power Association (IWPA) has financed the necessary meters.

NIWE identified two main challenges with getting the forecasting pilot off the ground: 1) getting TNEB to share the data; and 2) translating the data into a usable form. TNEB provided the needed data after a tripartite agreement was reached between NIWE, TNEB, and TNSLDC, which stated that the data would not be shared outside of this process. However, the meter data was provided in physical logs and on a monthly basis. Many of these logs dated back years, and were logged on a monthly basis because a joint meter reading between a representative from TNEB and the wind turbine owner was required every month. It took a year-and-a-half for NIWE to digitize the readings and change monthly readings to daily readings, which is the required input for the Vortex forecasting model. NIWE expects that getting a similar forecasting model off the ground in a new state would take about six months.

Once the forecasts are developed by NIWE, they are transmitted via email and FTP to the TNSLDC. TNSLDC created a dedicated portal for NIWE to upload forecast revisions intraday as well. TNEB has asked for the day-ahead forecasts to meet an 8% deviation tolerance, which NIWE said they were meeting, though subsequent conversations with the TNSLDC suggested that the error was closer to 15%.

Like Rajasthan, Tamil Nadu treats wind and solar energy as must-run and uses forecasts as the schedule for wind and solar generation. TNSLDC manually dispatches thermal resources through a merit order dispatch based on variable cost. All generators are put under merit order, including independent power producers, central generating units, and state generating units. Variable costs are updated on a monthly basis by generators. System constraints and local conditions may be considered in the dispatch decision. For example, if TNSLDC staff believe that load will be low for several days, they may manually de-commit a unit. Similarly, TNSLDC manually forecasts loads based on historical load data, weather, and rain conditions.

Day-ahead schedules are made from 10 am to 12 pm based on generation availability and load forecasts. Interstate generation schedules are provided by the RLDC and declarations must be made by 5 pm. At 5 pm, TNSLDC goes to the power exchange to buy power or sell surplus power. If the exchange does not elect TNSLDC's nomination, then TNSLDC moves to un-requisitioned surplus power (URS)²² or changes dispatch of units within the state. TNSLDC staff stated that they choose which option to use based on price to stay in line with merit order dispatch. In supply constrained situations, TNSLDC's last resort is to shed load. To date, TNSLDC trades about 500 MW on average through the power exchange. TNSLDC determines the amount to be bid and TANGEDCO determines the rate at which to bid.

TNSLDC indicated that it runs all coal units no lower than at 70% of nameplate capacity and gas units no lower than 85% of nameplate capacity.

²² URS are power surpluses due to changes in state declarations.

TNSLDC is responsible for load and generation balancing. TNSLDC manually adjusts thermal resource schedules based on revisions to renewable forecasts. It makes intraday changes to intrastate generator schedules directly through phone calls to generators. Generators can typically respond to these requests within 40 minutes to an hour from the phone call. For interstate generators, TNSLDC uses the RLDC's website to indicate changes to entitled central station units. The RLDC website will also post any URS available for TNSLDC to use for intraday balancing. TNSLDC indicated that URS' availability was limited because those units were being used to provide ancillary services under the new interstate *Ancillary Services Operations Regulations*.

With the thermal fleet within Tamil Nadu restricted to backing down to 70% (for coal) or 85% (for natural gas) of its capacity, TNSLDC only has 15%-30% headroom to balance its growing renewable resource share. According to IWPA, limited flexibility has led to large amounts of wind curtailment in the monsoon season when the wind is blowing and load is low.

TNSLDC also expressed that it is interested in exporting wind power. However, because not all wind is currently under forecast TNSLDC's day-ahead schedules can vary significantly from actual generation, which results in high DSM charges if the wind is not curtailed. There are currently no provisions in wind tariffs that address curtailment, which means that developers are left uncompensated if the wind is curtailed. Thus, developers have begun to seek legal action for curtailment of their facilities. TNSLDC stated that they curtail wind for reliability purposes, though representatives from the wind industry refute this claim and state that it is against merit order dispatch principles and not about reliability. Some of the legal battles in court are trying to determine the exact cause of curtailment.

In addition to physical balancing, Tamil Nadu has financial balancing mechanisms for banking wind energy over a fiscal year. When a customer enters into a wheeling agreement with TNEB, they are allowed the option to bank energy. For example, consider a commercial customer that develops a wind plant that generates 1,000 MWh in a month. The commercial customer only uses 800 MWh that month, so TNEB adjusts the customer's bill and puts 200 MWh in the bank. If the customer does not use the energy in its bank by the end of the fiscal year, TNEB is required to pay the customer 75% of the wind tariff rate for the energy that is in the bank. TNEB estimated that 20% to 30% of the wind is being banked between the monsoon season and other times of year. The banking concept is also present in other states, though the terms of the banking appear to be state specific. Andhra Pradesh, for example, allows banking over two months only.

TNEB has requested TNERC to review banking, as it feels that it is overpaying for banked power. TNEB's argument is that the power used by "banking" customers in the middle of the day, when the wind is not blowing, is much less expensive than the cost of the power those customers' wind facilities are producing at night, when TNSLDC is in minimum load conditions.

2.3 Priority Areas for Renewable Integration

Based on the review in Sections 2.1 and 2.2, and drawing on a renewable integration study conducted under Greening the Grid,²³ we identify four priority areas for enhancing forecasting, scheduling, and balancing of renewable energy in India. These include:

- 1) Enabling economic dispatch;
- 2) Enabling greater regional coordination;
- 3) Increasing resource flexibility; and
- 4) Clarifying roles, responsibilities, and authority.

The remainder of this section describes each of these areas.

2.3.1 Enabling Economic Dispatch

Variable renewable energy (VRE) poses unique challenges for load dispatch centers as they implement economic, or merit order, dispatch. We define “economic dispatch” as the marginal cost-based dispatch of generation units to minimize total operating costs. Like hydropower and nuclear power, variable renewable generation has high fixed costs and very low variable costs. However, variable renewable generation is more variable and less predictable than either hydropower or nuclear power. It is also more likely to be independently owned, which raises issues of open access to the electricity grid.

The high fixed-low variable cost structure of VRE suggests that, under economic dispatch, it should be dispatched whenever it is available. However, due to its high fixed costs, its levelized costs are often “above market.” In other words, market prices may not support investment in variable renewable generation on their own.

Curtailment is the largest challenge associated with the dispatch of VRE. Some amount of renewable energy curtailment will be economic. Regulatory and market institutions play a critical role in determining how much curtailment is economic.

For instance, RPO enforcement and curtailment terms in contracts provide an important signal for the economic dispatch of VRE, by creating an implicit cost for renewable energy curtailment. Additionally, and particularly in states where open access customers are signing contracts with renewable generators, open access regulations — including those for energy imbalance and congestion management — play an important role in supporting the economic dispatch of renewable generation. Other regulations and rules, such as those for self-scheduling, influence incentives for renewable energy curtailment.

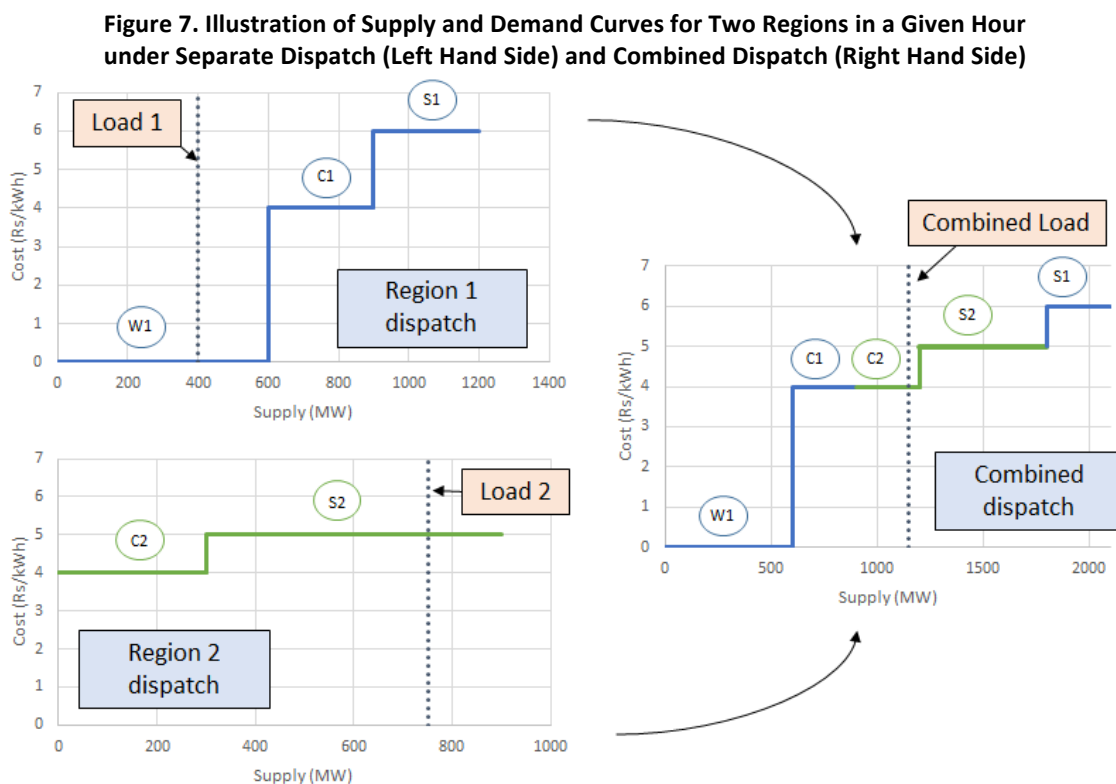
Section 3.2.1 describes the recent shift toward thinking about VRE as a dispatchable resource in the U.S., and how renewable policy support mechanisms, open access regulations, and ongoing changes in market rules shape incentives for economic dispatch.

²³ This study includes production simulation modeling work. The results will be finalized in March 2017.

2.3.2 Enabling Greater Regional Coordination

As renewable energy penetrations increase, a key challenge to maximizing its value will be in reducing barriers to the exchange of intrastate renewable generation across state boundaries. Doing so requires greater coordination among SLDCs, so that merit order dispatch within states increasingly resembles a merit order dispatch for regions.

Figure 7 shows an illustrative example, with separate hourly supply and demand curves for two regions where each region is dispatched separately (left hand side) and a joint hourly supply and demand curve for both regions where both regions are dispatched jointly (right hand side).



(W1 is wind generation in region 1, C1 is region 1’s share of a 600 MW interstate generator, S1 is a 300 MW intrastate generator in region 1; C2 is region 2’s share of the 600 MW interstate generator, S2 is a 600 MW intrastate generator in region 2)

If both regions are dispatched separately, region 1 is forced to curtail wind generation (W1) and leave its allocation of an interstate low cost thermal generator (C1) unused, which in turn forces region 2 to run its more expensive generator (S2). If both regions are dispatched jointly, all generation can be absorbed and the lower cost interstate thermal generator (C1) can operate all full output, avoiding the need to operate more expensive generator S2.

The marginal cost will be lower for the two regions together rather than separately, but the figure illustrates the economic transfers that might result from joint dispatch. If there is a single market clearing price, customers in region 1 will face higher wholesale prices, while the wind generator will earn higher revenues. Customers in region 2 will see lower wholesale prices, but the intrastate generator in

region 2 will not be dispatched at all. Thus, regional coordination requires mechanisms for fair benefit and cost allocation.

Section 3.2.2 summarizes recent developments in regional coordination in the Western U.S., describing efforts by utilities, system operators, and regulators to create centralized, regional mechanisms for intra-hour balancing.

2.3.3 Increasing Resource Flexibility

From the U.S. to Germany and China, rising penetrations of VRE are changing the ways in which coal generators are dispatched. In India, higher penetrations of variable renewable generation are also likely to change how coal generators are used. Greater flexibility in loads could mitigate some of these impacts and provide a low-cost means of better integrating renewable energy.

In many countries, including India, coal generating units were historically designed and expected to operate as baseload units. They required a day or more to start up, usually stayed on for long time periods once they were started up, had limited ramping requirements, and typically did not operate below 50% to 70% of their nameplate capacity. Integration of VRE is requiring coal units to operate at lower minimum generation levels, ramp more frequently and over a larger output range, and more frequently start up and shut down (“cycle”).²⁴

On the demand-side, emerging technologies and operating strategies — such as energy management systems for automated demand response, smart charging for electric vehicles, customer-side energy storage, and smart inverters on distributed PV systems — can enable load to better follow renewable generation, reducing the need to ramp and cycle coal units. These demand-side technologies could have important applications for renewable integration in India.

Section 3.2.3 describes efforts by plant owners, utilities, and regulators to make coal units and loads more flexible, including changes in incentives to compensate owners and operators for their higher costs.

2.3.4 Clarifying Roles and Responsibilities, and Authority

Low-cost integration of renewable energy will require efficient interoperation of India’s interstate and intrastate power systems. Efficient interoperation, in turn, will depend on clear delineation of roles, responsibilities, and authority — (1) vertically, among national, regional, and state organizations, and (2) horizontally, among system operators, generators, transmission owners, and service providers — as the interstate-intrastate system evolves in response to higher penetrations of renewable energy.

The U.S. electricity sector has undergone similar institutional and organizational changes over the last two decades. Additionally, with the recent emergence of centralized balancing mechanisms in the Western U.S., vertical and horizontal roles and responsibilities in that region are now changing. U.S.

²⁴ Recent CERC policy changes will reduce minimum generation levels to 55% for interstate units.

experience in demarcating roles, responsibility, and authority in an evolving regional, federalist context is described in Section 3.2.4.

3 U.S. Experience with Forecasting, Scheduling, and Balancing of Renewable Energy

As Indian regulators seek to address emerging challenges in the forecasting, scheduling, and balancing of renewable energy, U.S. experience may offer useful insights. This section draws on three case studies to examine how the four priority areas identified in the previous section have been, or are being, addressed in a U.S. context.

The section first provides essential background on ownership and industry structure in the U.S. electricity sector, along with an overview of the three case study areas. It then describes U.S. experience in the four priority areas:

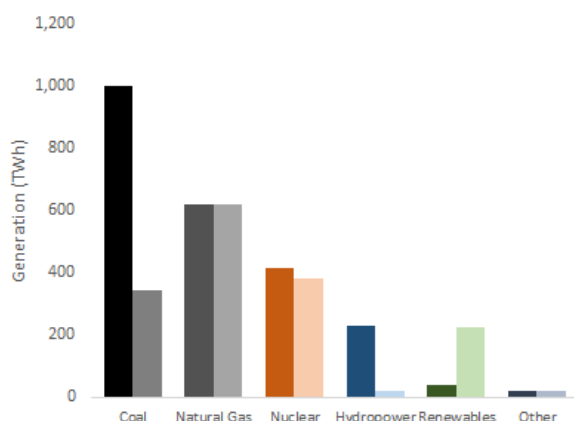
- **Enabling economic dispatch** — *how policy, open access regulations, and market designs has shaped the economic dispatch of VRE in the U.S.*
- **Enabling greater regional coordination** — *how U.S. states expanded power system coordination to better integrate renewable energy*
- **Increasing resource flexibility** — *how power systems in the U.S. increase flexibility on the supply and demand sides, to provide system operators with more options to accommodate variability and uncertainty in wind and solar generation*
- **Clarifying roles, responsibilities, and authority** — *how roles, responsibilities, and authority of regulators, system operators, utilities, and generators in the U.S. have evolved to address renewable integration challenges*

3.1 Background

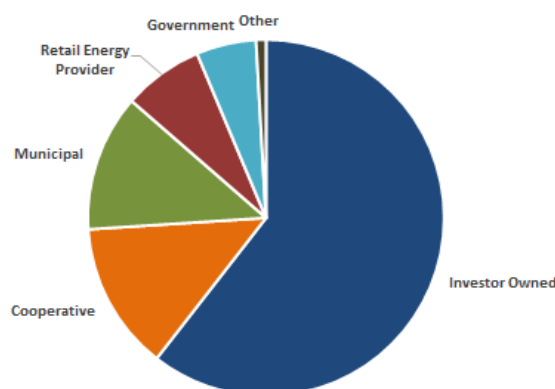
3.1.1 Ownership, Regulation, and Industry Structure

Figure 8. Independent power producers now account for a large share of gas-fired-, nuclear, and renewable generation (A); most electricity sales are by a diverse mix of incumbent utilities (B)²⁵

A. Generation by Producer Type, 2015 (utilities in the left-hand column, independent power producers in the right-hand column)



B. Share of Electricity Sales by Seller Type, 2014



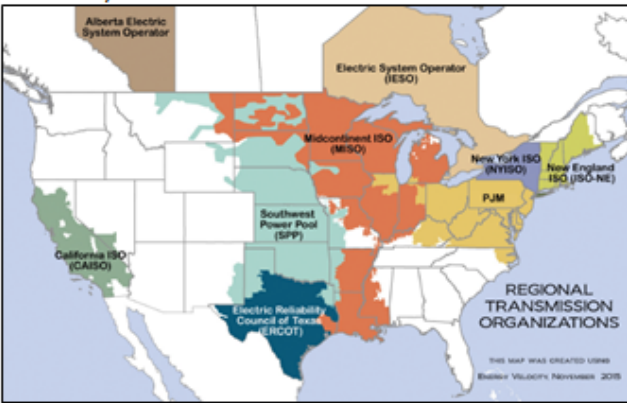
²⁵ Generation data (A) are from the U.S. Energy Information Administration (EIA), “Net Generation by Energy Source,” <http://www.eia.gov/electricity/annual/>. Electricity sales data (B) are from EIA, “Form EIA-826 detailed data,” <https://www.eia.gov/electricity/data/eia826/>.

The U.S. electricity sector has always been organizationally complex and highly fragmented, with numerous actors and a diverse mix of private and public ownership. Independent power producers now account for 50% of gas-fired and nuclear generation and 85% of renewable generation (Figure 8A), with public and private utilities generating the remainder. A large number of incumbent utilities still account for the majority of electricity sales, including 199 regulated investor-owned utilities (61% of total sales), 856 rural electric cooperatives (13%), and 824 publicly-owned municipal utilities (12%) (Figure 8B).

Like India, the U.S. electricity regulatory system has a federalist division of powers that is rooted in law. The Federal Energy Regulatory Commission (FERC) has jurisdiction over interstate transactions, which effectively gives it oversight over the high voltage (“bulk”) transmission system in most states. States have jurisdiction over distribution systems and retail pricing. The interplay between federal and state regulatory authority shapes many of the issues discussed in this section.

Figure 9. Most of the Western and Southeastern U.S. does not participate in an RTO/ISO (A); trading hubs play an important role in economic dispatch (B); the Western U.S. has a many balancing areas (C)

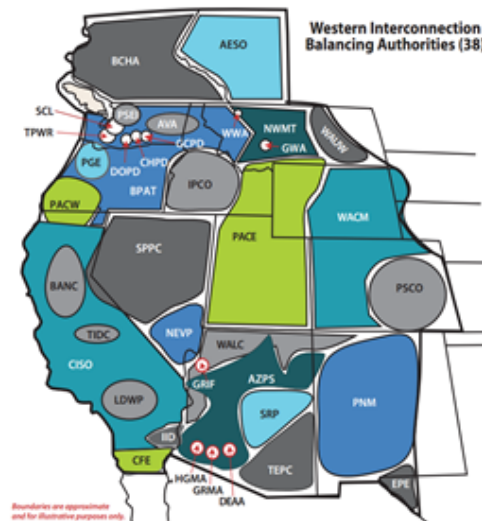
A. RTOs/ISOs in the U.S.



B. Major Trading Hubs in the Western U.S.



C. Balancing Areas in the Western U.S.



Since the 1990s, the U.S. has seen the growth and expansion of regional transmission organizations (RTOs) and independent system operators (ISOs) that operate wholesale markets.²⁶ However, large portions of the U.S., including most of the Western and Southeastern U.S., are not part of an RTO or ISO (Figure 9A) — with California being the major exception. In these regions, utilities still trade with one another and purchase power from non-utility generators through trading hubs (Figure 9B) and bilateral (over-the-counter) trades and power exchange. In the Western U.S., bilateral exchange plays a particularly important role in coordinating among utilities because of the large number of balancing (control) areas — a total of 38 (Figure 9C).

Across jurisdictions in the U.S., industry structures can be categorized by two main features: (1) the extent of retail competition,²⁷ if any; and (2) whether the jurisdiction participates in an RTO or ISO (Table 4). Table 4 illustrates that there is no simple taxonomy for the U.S. electricity industry. RTOs typically include a mix of vertically integrated utilities and competitive retail providers, as a result of different policies among states within the RTO region. Municipal utilities in states with ISOs may (Texas) or may not (parts of California) participate in ISO markets.

Table 4. Industry structures in the U.S. can be categorized by the extent of retail competition and RTO/ISO participation (see Figure 9A for RTO/ISO footprints)

Retail Competition	RTO/ISO Participation	
	No	Yes
No	<u>Vertically integrated utility</u> <ul style="list-style-type: none"> ○ Public Service Colorado (Colorado) ○ Los Angeles Department of Water and Resources (California) 	<u>Vertically integrated utility</u> <ul style="list-style-type: none"> ○ Dominion Power (Virginia), PJM ○ Northern States Power (Minnesota), MISO ○ CPS Energy (Texas), ERCOT
Limited	<u>Vertically integrated utility with limited direct access</u> ²⁸ <ul style="list-style-type: none"> ○ PacifiCorp (Oregon) 	<u>Vertically integrated utility with limited direct access</u> <ul style="list-style-type: none"> ○ DTE Energy (Michigan), MISO
		<u>Restructured utility with limited direct access</u> <ul style="list-style-type: none"> ○ PG&E (California), CAISO
Yes	N/A	<u>Default service provider</u> <ul style="list-style-type: none"> ○ ConEd, NYISO (New York) ○ AEP (Pennsylvania), PJM
		<u>Wires only company with separate provider of last resort</u> <ul style="list-style-type: none"> ○ Oncor (Texas), ERCOT

²⁶ The main difference between an RTO and ISO is now that an RTO operates across states, and an ISO operates within a state.

²⁷ “Retail competition” in the U.S. refers to the opening up of vertically integrated utilities’ retail business to either competitive third-party retail providers or large industrial customers that procure capacity and energy directly from generators or the energy market.

²⁸ “Limited direct access” refers to cases in which a limited number of customers are able to freely choose their suppliers.

3.1.2 Description of Case Study Areas

The three case studies represent different kinds of system operators within the spectrum of industry structures described in Table 4. These case studies were selected because of their relevance to the Indian context.

- **California Independent System Operator (CAISO), California.** The CAISO is an independent system operator that manages the high voltage transmission system for most of California and a small part of Nevada, and administers day-ahead, real-time, and ancillary services markets.
- **PacifiCorp, Oregon.** PacifiCorp is a vertically integrated utility, headquartered in Oregon, that operates electric grids across parts of six different states — California, Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp recently established a joint energy imbalance market (EIM) with the CAISO, though it is not technically part of an RTO or ISO.
- **Public Service Company of Colorado (PSCo), Colorado.** PSCo is a vertically integrated utility owned by Xcel Energy, a holding company that owns utilities in eight states. PSCo is not part of an RTO or ISO, though it recently signed a joint agreement with two neighboring utilities for centralized real-time dispatch.

All three of these entities are effectively system operators, though CAISO is independent and PacifiCorp and PSCo are vertically integrated utilities. PacifiCorp and PSCo have recently joined, or are joining, centralized balancing markets. The three entities facilitate different levels of trade through their transmission systems (Table 5).

Table 5. CAISO, PacifiCorp, and PSCo are different kinds of system operators and

System operator	Type	Centralized markets	Level of trade facilitation
CAISO	Independent system operator	CAISO	High
PacifiCorp	Vertically integrated utility	CAISO EIM	Low
PSCo	Vertically integrated utility	None; creating joint dispatch	Medium

3.2 U.S. Experience

3.2.1 Enabling Economic Dispatch

Key Questions:

- How is ‘economic dispatch’ defined in the U.S.?
- Why is it important for supporting VRE?
- How do RPS policies, contract terms, open access regulations, and market design shape the economic dispatch of VRE?

In the U.S., economic dispatch is officially defined as “the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities.”²⁹ In practice, economic dispatch is implemented in the U.S. using software to minimize total operating costs over the course of a day, subject to grid security constraints. In RTO markets, cost minimization is on the basis of market participants’ marginal cost-based bids. In non-RTO areas, cost minimization is on the basis of generator variable costs. In both cases, generators’ fixed costs are not included in the cost minimization.

Economic dispatch has been an important enabler of variable generation in the U.S. Historically, wind and solar generation were considered to be non-dispatchable (“must-run”) resources. Increasingly, wind and solar generation are being viewed and operated as fully dispatchable resources, able to provide the same services — voltage control, frequency response, ramping support — as conventional generators. Wind and solar generators are dispatched by curtailing their output.

This shift toward greater dispatchability of wind and solar generation has also prompted a shift from thinking about wind and solar curtailment as a reliability problem to thinking about it as an economic problem. “Economic” curtailment of wind and solar generation then raises the question: How much curtailment is economic?

This section describes three areas of policy and regulation that shape how VRE is treated in economic dispatch in the U.S.: (1) renewable portfolio standards (RPS), which are functionally similar to India’s RPOs, and power purchase contract terms; (2) open access regulations; and (3) market rules.

3.2.1.1 *Renewable Portfolio Standards and Contract Terms*

Renewable energy development in the U.S. has been driven to a large extent by state RPS targets. RPS targets provide a means to reconcile the “above-market” costs and low marginal costs associated with VRE. That is, once VRE is installed it should be operated as much as possible because it has very low marginal costs. However, the costs of building variable renewable generation are often higher than average market or utility costs.

²⁹ DOE (2007).

This dynamic between fixed and variable costs can be most easily understood in the context of vertically integrated utilities. A utility that owns wind generation, for instance, will seek to ensure that it operates whenever available in order to minimize the utility's fuel costs. However, the utility will need to have a reason and regulatory approval to build the wind generation in the first place, particularly if the cost of wind generation will increase the utility's average costs.

Non-utility wind and solar generators typically require long-term power purchase agreements (PPAs) to secure financing. Without an RPS requirement or specific terms in the contract that limit curtailment, the marginal choice for load serving entities will often be between paying a higher PPA price for wind and solar generation and using / buying cheaper generation. Without incentives to the contrary, load serving entities will tend to try to shift curtailment costs onto wind and solar generators.

RPS Requirements, Contracts, and Economic Dispatch

Consider a small regulated utility with 1,000 GWh of sales and a 30% RPS requirement that will require it to procure at least 300 GWh of energy from renewable generators. The penalty for RPS noncompliance is \$100 per MWh below the RPS obligation and the utility will be required to absorb these costs.

The utility signs a \$40/MWh contract with for 125 MW of wind that it projects will have a 30% capacity factor, generating 329 GWh of energy and allowing the utility to safely meet its RPS target. The utility projects that it will need to curtail the wind energy on some occasions for reliability and economics. Its replacement cost for renewable energy is \$50/MWh.

To keep curtailment rates below 29 GWh (9.5%) and avoid noncompliance penalties, the utility would be willing to pay up to \$50/MWh or \$100/MWh, depending on the timing of RPS enforcement. To ensure that wind is dispatched efficiently, the utility incorporates the wind generation into its security constrained economic dispatch at a price of -\$50/MWh. Below this price (more negative), it will be more economic for the utility to buy more renewable generation replace generation from the wind project.

This implicit price helps to guide the utility's dispatch decisions. For instance, if the utility has a take-or-pay contract with a natural gas generator for \$30/MWh, the \$50/MWh replacement cost suggests that it will be more economic to "curtail" the natural gas generator and dispatch the wind generator, if the utility were forced to choose between the two.

Curtailment terms in renewable generator contracts can have a similar effect as a replacement value. For instance, if the utility agrees to pay the wind generator \$40/MWh for curtailment above a 5% level, the utility will use -\$40/MWh as a marginal price to guide marginal procurement decision-making.

Penalties for RPS noncompliance and contractual requirements thus provide an important signal for economic dispatch, by providing an incentive for load serving entities to treat wind and solar generation more as low marginal cost resources, rather than resources with high PPA prices. RPS penalties and contractual terms effectively acts as an implicit price for wind and solar curtailment. The box above explains the mechanics of this implicit price.

3.2.1.2 *Open Access Regulations*

Open access regulations in the U.S. shape the economic dispatch of variable renewable generation in two important ways: (1) they provide a means for non-utilities to schedule and balance variable renewable generation on utility-owned transmission systems; and (2) they provide marginal incentives for the curtailment of variable renewable generation.

Open access regulations in the U.S. stem from FERC's Order 888 (1996), which required utilities to provide non-utility generators with non-discriminatory access to their transmission systems. Within Order 888 and FERC's subsequent open access orders,³⁰ requirements for mechanisms to address energy imbalances and congestion-related redispatch play an important role in shaping the dispatch of variable renewable generation.

Non-RTO utilities and RTOs/ISOs have taken different approaches to meeting these requirements. In non-RTO contexts, FERC requires that utilities offer transmission services to third parties that are comparable to what they "offer" themselves, including physical rights to the transmission system, energy imbalance services, and redispatch services (Table 6). In RTO/ISO contexts, RTOs/ISOs met these requirements through locational marginal price- (LMP-) based real-time markets and financial transmission rights (Table 6).³¹

³⁰ These include Order 889, 890, and 2000.

³¹ FERC Order 2000 required RTOs to develop these market-based methods for congestion management. LMPs are marginal prices at different nodes within a system, and reflect the marginal cost of generation and transmission losses at each node. In simple terms, LMPs represent the lowest cost to supply energy at that point in the system due to the combined effect of generator availability and transmission constraints. Financial transmission rights enable the owner to earn the difference between LMPs at different price nodes.

Table 6. Open access mechanisms to support economic dispatch vary across non-RTO and RTO/ISO contexts

Non-RTO	RTO/ISO
<p><i>Physical rights.</i> Generators can purchase firm, conditional firm, and non-firm transmission rights. If the network is congested, non-firm schedules are curtailed first, conditional firm second, and firm rights last.</p>	<p><i>Financial rights.</i> Generators and customers can purchase financial transmission rights, which allow the rights holder to hedge differences in locational prices if the network is congested.</p>
<p><i>Redispatch service (“planned redispatch”).</i> Generators can pay utilities to redispatch utility-owned generation to relieve congestion, instead of curtailing non-utility-owned generation.</p>	<p><i>Real-time market.</i> Schedulers (generator or load) that have imbalances pay or are paid at the real-time LMP. If the network is congested, the system operator redispatches based on economic bids in the real-time market to the extent possible. Nodal pricing reduces the need for redispatch.</p>
<p><i>Energy imbalance service.</i> If actual generation deviates from schedule within a preset range, generators pay (or are paid) the utility’s incremental cost; at higher deviations charges (payments) are at FERC-regulated multiples of incremental cost.</p>	

Two terms from the “non-RTO” column of Table 6 warrant further description. First, FERC proposed the “conditional firm” category specifically to provide variable renewable generation with an alternative to firm transmission service, which is priced on a capacity (dollars per MW per time period) basis and is thus an expensive way for renewable generators to hedge against congestion. Conditional firm service provides firm rights during all hours except a limited number of on-peak and other utility-designated hours. Second, both conditional firm service and redispatch service require requests from generators and trigger utility studies to determine if they can be made available. In both cases, they were meant to provide short-term relief from congestion-related curtailment until the transmission system could be upgraded to relieve congestion.

Open access mechanisms have played an important role in supporting the economic dispatch of non-utility renewable generation, by providing a cost-based (non-RTO) or bid-based (RTO/ISO) price for schedule imbalances and curtailment. In a non-RTO context, renewable generators pay or are paid for schedule deviations (forecast error) based on the utility’s incremental cost — its cost of supplying an equivalent amount of energy. To reduce the financial risks of congestion, non-utility renewable generators can buy firm or conditional firm transmission rights, or in principle, could pay utilities for redispatch service.

In an RTO/ISO context, renewable generators or their schedulers pay or are paid for schedule deviations at the real-time LMP. Renewable-energy-related congestion is managed through economic bids in the real-time market before resorting to “non-economic” curtailment of renewable energy. RTO/ISO

markets thus naturally provide a means to manage the schedule deviations and congestion associated with variable renewable generation.

Open access mechanisms also play an important role in shaping marginal incentives for curtailment, by revealing prices for curtailment. The following box illustrates how these open access mechanisms shape marginal incentives in cost-based and market-based environments.

Open Access, Economic Dispatch, and Renewable Energy

As the below example illustrates, open access rules in non-market and market contexts differ and their outcomes are not strictly comparable, but in both cases open access supports economic dispatch of renewable energy, leading to lower short-run costs and prices.

Consider a wind generator that has signed a \$40/MWh power purchase agreement (PPA) with a utility. The PPA does not specify terms for curtailment. The wind generator forecasts that it will have an average of 100 MW of output in some off-peak hours. The utility forecasts that it will have 1,000 MW of load in that hour, but has already scheduled 1,000 MW of its own generation to meet that load. The utility's marginal unit is a 100 MW thermal generator with a variable cost of \$30/MWh.

How would this situation be resolved in non-market and market contexts?

Non-market. The wind generator will lose all of its revenue if it is curtailed, so it will generally be willing to pay for transmission service or for the utility to redispatch the 100 MW generator in order to receive its PPA price. Because the wind generator's marginal cost is near \$0/MWh, it would, in principle, be willing to pay the utility up to its PPA price of \$40/MWh for short-term firm transmission service or redispatch service. The utility would have cost savings of \$30/MWh from dispatching the wind, but would have to pay the \$40/MWh PPA price.

If the utility's daily rate for off-peak transmission service is \$25/MW-day, the wind generator would earn net revenues of \$1,500 ($= [\$40/\text{MWh} - \$25/\text{MW-day} - \$0/\text{MWh}] * 100 \text{ MW}$) and the utility would earn net revenues of \$1,500 ($= [\$25/\text{MW-day} + \$30/\text{MWh} - \$40/\text{MWh}] * 100 \text{ MW}$) in that hour. If the utility has published a redispatch cost of \$15/MWh, the wind generator would earn net revenues of \$2,500 ($= [\$40/\text{MWh} - \$15/\text{MWh} - \$0/\text{MWh}] * 100 \text{ MW}$) and the utility would earn net revenues of \$5/MWh ($[\$15/\text{MWh} + \$30/\text{MWh} - \$40/\text{MWh}] * 100 \text{ MW}$) in that hour. Regardless of whether the wind generator selects firm transmission or redispatch service, both the wind generator and the utility are better off than they would have been under the counterfactual, where the wind generator is curtailed.

Market. Assume that the wind generator and utility are now part of a larger market. The generator bids into the market directly, and the PPA between the generator and utility is a contract for differences. The wind generator will bid into the market at a zero (or negative) price, as it earns no revenues if it does not clear the market. Assume that the marginal generator would have been the utility's \$30/MWh 100 MW unit, but that the wind generator displaced this unit and that the new LMP is \$25/MWh.

The wind generator is paid \$2,500 ($= \$25/\text{MWh} * 100 \text{ MW}$) by the system operator and \$1,500 ($= [\$40/\text{MWh} - \$25/\text{MWh}] * 100 \text{ MW}$) by the utility for the contract for differences, earning its full PPA value of \$4,000 in that hour. The utility pays \$25,000 to the system operator ($= \$25/\text{MWh} * 1000 \text{ MW}$), and \$1,500 to the wind generator ($= [\$25/\text{MWh} - \$40/\text{MWh}] * 100 \text{ MW}$), reducing its procurement costs from \$30,000, with a \$30/MWh LMP, to \$26,500. Whether, on balance, this situation is better economically for the utility will depend on the opportunity cost of lost inframarginal rents on its own generation from the reduction in LMP. In any case, the wind generator will reduce market energy prices for all customers.

3.2.1.3 *Market Designs*

Even within organized markets, RTOs and ISOs in the U.S. have continued to remove barriers to economic dispatch in response to rising penetrations of renewable energy. CAISO provides an illustrative example. Before its market redesign and technology upgrade (MRTU) in 2009, CAISO was essentially a bilateral market, where scheduling entities submitted nearly balanced schedules to the CAISO and were required to purchase (or sell) any shortfalls (surpluses) in the CAISO's real-time energy market. Generators and non-utility loads were able to purchase physical transmission rights to hedge against congestion in the real-time market.

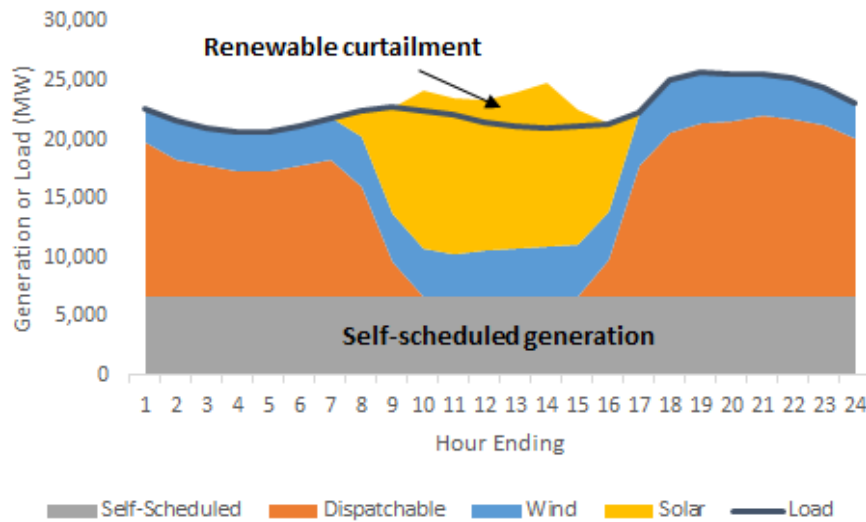
With MRTU, CAISO created a financially binding day-ahead market and moved from zonal pricing and physical transmission rights to LMPs and financial transmission rights. Scheduling coordinators — organizations authorized to submit schedules — were still able to “self-schedule” resources as price takers, submitting quantity (MW) bids without a corresponding price (\$/MWh) bid. CAISO also grandfathered some existing firm transmission rights holders into this new system. Self-scheduled bids and existing rights holders were granted priority in dispatch, because they had no price associated with their bids and thus were technically not part of economic dispatch. CAISO would manually curtail these resources on a pro rata basis during congestion events.³²

Rising penetrations of renewable energy made this system more obviously uneconomic. In 2010, a CAISO study found that self-scheduling would be an obstacle to meeting California's 2020 renewable portfolio standard goal, which at the time was 20%.³³ Self-scheduling effectively created an inflexible block of generation that could not be redispatched in the CAISO's normal market processes, and would force the CAISO to curtail renewable generation rather than economically backing down self-scheduled generation (Figure 10).

³² For more on current self-scheduling practices within the CAISO, see the CAISO tariff, https://www.caiso.com/Documents/ConformedTariff_asof_Apr25_2016.pdf.

³³ CAISO (2010).

Figure 10. Self-Scheduled Generation Leads to Higher Levels of Renewable Curtailment (Illustrative Example)³⁴



In 2014, the California Public Utilities Commission (CPUC) and the CAISO responded by requiring LSEs to hold a minimum quantity (MW) of flexible resources for each month, defined in terms of ramping capability. The CPUC and CAISO required these resources to submit economic bids into the CAISO energy markets. This program, known as flexible resource adequacy criteria and must-offer obligation (FRAC-MOO), reduces the amount of self-scheduling by requiring some previously self-scheduled resources to submit economic bids.³⁵ In addition to FRAC-MOO, the CAISO has proposed or undertaken a number of other initiatives to expand economic dispatch, including lowering the bid floor and forcing self-scheduled generators to pay bid cost recovery costs.³⁶ These initiatives will increasingly allow the CAISO to curtail schedules according to economic bids rather than doing so manually on a pro rata basis.

³⁴ This figure is based on 2015 load, solar, and wind data for the CAISO, adjusted so that wind and solar account for 8% and 17%, respectively, of total system energy (from 5% and 4% in 2015), and assuming self-scheduled energy accounts for 25% of total system energy.

³⁵ For more on FRAC-MOO and how it functions in the CAISO market, see Cynthia Hinman, 2014, “Flexible Resource Adequacy and Must Offer Obligation (FRAC MOO) Pre-Market Sim Training,”

https://www.caiso.com/Documents/Presentation-FlexibleResourceAdequacy_MustOfferObligationTraining.pdf.

³⁶ Specifically, CAISO proposed lowering the bid floor from negative \$150/MWh to negative \$300/MWh, requiring generators to pay more to remain online during congestion events. By requiring scheduling coordinators to pay bid cost recovery costs — bid costs not recovered through the market — for all generation, and not just those submitting economic bids, the CAISO provides an additional disincentive for self-scheduling. See Kallie Wells, 2016, “Self-Schedules Bid Cost Recovery Allocation and Bid Floor: Draft Final Proposal,”

http://www.caiso.com/Documents/Agenda_Presentation_Self_SchedulesBidCostRecoveryAllocation_BidFloor.pdf.

Summary:

- Open access rules have been important for the economic dispatch of renewable energy in the U.S.
- Economic dispatch of variable renewable energy suggests that it should be dispatched almost all the time, unless not doing so would lead to reliability violations.
- Combined with platforms for interstate trade, cost-based congestion management and imbalance energy mechanisms could, in principle, provide a partial solution for economically rationalizing curtailment and deviation of generator schedules.
- Limitations in cost-based approaches have led utilities and states to explore participation in regional markets, described later in this section.
- Even within markets, market designs are continuing to evolve to enable an expansion of economic dispatch that supports variable renewable energy.

3.2.2 Enabling Greater Regional Coordination

Key Questions:

- What has motivated increased regional coordination in the U.S.?
- What are examples of U.S. models of regional coordination and to what degree do they differ from operations in a vertically integrated utility without access to centralized markets?
- What is the value proposition of extending a balancing area (i.e., centralizing operations across multiple balancing areas)?

One of the most robust and significant findings from the growing body of work on renewable energy integration is the importance of closer coordination among local balancing areas for reducing the investment and operating costs of high penetration renewable electricity systems. Although “regional coordination” and “larger balancing areas” have become standard prescriptions for renewable energy integration, cooperation across states or countries is often, in fact, not a simple matter. Utilities in roughly one-third of U.S. states, for instance, have historically not been part of a regional balancing area. Past attempts to regionalize in the Western U.S. have failed, including, Independent Grid Operator (IndeGO), Regional Transmission Organization West (RTO West), Grid West, and Desert Star, among others. There was a confluence of factors that kept these efforts from succeeding, of which the California electricity crisis was the largest. The electricity crisis happened from 1999-2001 after California unbundled its vertically integrated utilities and created a set of wholesale markets to facilitate electricity transactions. Prices soared during the crisis, as there was market manipulation which led to lack of supply, and the state experienced rolling blackouts. The crisis made many people in the West wary of competitive wholesale energy markets.

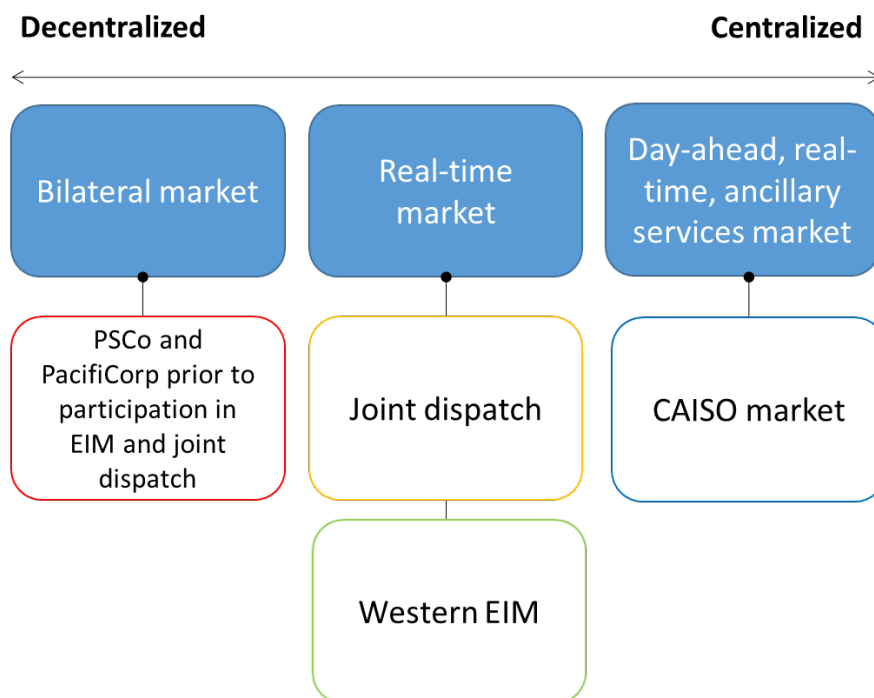
However, the changing dynamics of the grid, such as changing power flows due to wind and solar, successful track record of wholesale markets in other parts of the U.S., and low-cost, low-risk regional

coordination mechanisms, such as real-time markets that use existing transmission capacity, have encouraged more regional coordination in recent years. In addition, the regional mechanisms that have recently succeeded in the Western U.S. have been incremental to existing system operations and avoid large changes in regulatory authority between state and federal regulators.

Historical and more recent U.S. experience illustrate the ways in which coordination among state-oriented balancing areas can evolve. RTOs in the U.S. often grew out of regional power pools, where utilities across multiple states pooled their generation and loads and an independent regional system operator dispatched generation to meet demand at the least possible cost. Power pools typically had clear cost savings and transparent mechanisms to allocate those savings among member states, and RTOs were able to build on these kinds of cooperative mechanisms.

This section will focus on two of the case studies, PSCo and PacifiCorp, and walk through their transitions from utilities with no exposure to centralized markets to participation in joint dispatch and energy imbalance markets, respectively. Figure 11 below shows where the case studies fall along the spectrum of regional coordination mechanisms, with more centralization occurring as activities become more coordinated regionally. PSCo and PacifiCorp started in purely bilateral markets (left end of figure), have moved to participating in real-time market like mechanisms (middle of the figure), and are evaluating full centralized market participation (right end of figure).

Figure 11: Regional coordination spectrum in case studies



The case studies will highlight the motivation to move towards regional coordination and describe the evaluation process each utility underwent to determine the value of moving to a regional market

structure for its customers. It also touches on the role the state and federal regulators played in the development of each regional market mechanism.

3.2.2.1 *Public Service of Colorado (PSCo)*

Colorado has ambitious renewable energy goals -- a 30% RPS by 2020 for investor owned utilities and a 10%-20% RPS by 2020 for municipal utilities and electric cooperatives depending on their size.³⁷ Of the wind resources developed to meet the RPS to date, PSCo owns or operates close to 95% of them.³⁸ For a small balancing area authority with limited transmission connections to neighboring markets, PSCo has become adept at operating high wind electric systems on its own. It has been a leader in developing wind forecasting techniques, testing system dispatch technologies and policies, and studying flexibility needs associated with high renewable systems. Even with all of these measures in place and ongoing research, PSCo has had to curtail about 3% of its wind generation due to limited flexibility within its balancing area.³⁹ PSCo's parent company's experience in regional markets in other parts of the country served as a good example for how market based electricity system can help integrate renewables, which motivated PSCo to explore what regional coordination market based mechanisms might work in the Colorado context.⁴⁰

PSCo recently collaborated with two other utilities in its balancing area (Platte River Power Authority (PRPA) and Black Hills Colorado Electric Utility Company (BHCE)) to enter into joint dispatch service.⁴¹ The joint dispatch service is offered through PSCo's open access transmission tariff (OATT), which is a tariff that provides different types of transmission service (including balancing) over a utility's transmission system.⁴² Though there are only three joint dispatch participants currently, the service was designed to be open access so that any entity in PSCo's balancing authority could participate. FERC approved of the service in February 2016.⁴³

Joint dispatch service is an intra-hour balancing service that pools together all the participating entities' elected generation resources⁴⁴ (including market purchases) and dispatches them in merit order to meet the combined entities' load (excluding sales associated with non-native load).⁴⁵ The motivation behind the joint dispatch service was the cost savings associated with dispatching the combined generation resources of all participating utilities to meet the combined load for intra-hour balancing (see Figure

³⁷ <http://programs.dsireusa.org/system/program/detail/133>

³⁸ http://nawindpower.com/online/issues/NAW1412/FEAT_01_Inside-Colorado-s-Wind-Integration-Success-Story.html

³⁹ Ibid.

⁴⁰ FERC (2016).

⁴¹ Xcel (2015).

⁴² OATTs were a requirement of FERC Order 888 for utility's to provide open access to their transmission system to all customers that requested service. OATTs list the types of transmission service the utility provides (e.g., network, point to point, conditional firm, joint dispatch).

⁴³ FERC (2016).

⁴⁴ Elected generation are resources that participants designate as dispatchable on an hourly basis and can be dispatched by PSCo for joint dispatch services in real-time.

⁴⁵ Native load are customers the utility is obligated to serve.

7).⁴⁶ Joint dispatch customers are paid, or pay, the cost based marginal clearing price⁴⁷ of PSCo's joint dispatch for any intra-hour imbalances. The service requires that each participating member (typically a utility) commits enough resources to meet its own hourly load requirements.⁴⁸ In addition, joint dispatch transactions can only occur on any unused available transmission capacity, which ensures that customers that have existing rights on transmission facilities are not impacted by joint dispatch service.⁴⁹ Key highlights from joint dispatch service include:

- No changes in system operations until the start of the hour (e.g., no changes in unit commitment, bilateral contract arrangements).
- Participants designate which of their generators they would like to be considered "dispatchable" in joint dispatch service at the beginning of each hour.
- PSCo dispatches elected generation in merit order to handle system imbalances in real-time.
- Real-time dispatch results in lower overall system imbalance cost relative to a system in which PSCo, as the imbalance service provider for all transmission customers, could dispatch its own generation in real-time to handle system imbalances.
- Settlement price is based on the system marginal cost, which is equivalent to the incremental cost of the next economic megawatt of power that could be dispatched under joint dispatch service.

The joint dispatch service is an incremental step towards market based solutions for the electricity sector in Colorado, which has not participated in centralized markets to date. In its filing to FERC, PSCo estimated savings of joint dispatch in the range of \$7.7 million in 2015.⁵⁰ PSCo also stated that the other participating utilities, PRPA and BHCE, did not have experience with centralized markets before and their participation in the joint dispatch service was partly to give them exposure and comfort to market based mechanisms.⁵¹ Because the development of joint dispatch service would impact PSCo's retail rates, PSCo also had to file for approval with the Colorado state regulator for how it would use the cost savings associated with joint dispatch.⁵²

PSCo and six other parties (see Figure 12 for map of combined service territory) are also currently evaluating the development of a single transmission tariff across their service territories to eliminate

⁴⁶ Xcel (2015).

⁴⁷ Costs are capped at the PSCo's cost based rates filed at FERC.

⁴⁸ Penalties are only applied when participants do not commit enough dispatchable resources to meet their hourly energy requirements or designate too many resources with limited flexibility to dispatch.

⁴⁹ This joint dispatch concept differs from traditional imbalance energy service, which is provided under Schedule 4 in PSCo's OATT. Traditional imbalance energy service charges (or pays) tiered imbalance penalties to customers that deviate from their schedules. These penalties increase the greater the deviation and are priced at a percentage of the imbalance energy (MWh) times PSCo's marginal generation cost for that hour (dollar per MWh). The imbalance accounting is done on a customer by customer basis and PSCo is only able to use its own generation resources to serve the imbalance needs of all its non-joint dispatch OATT customers' imbalances.

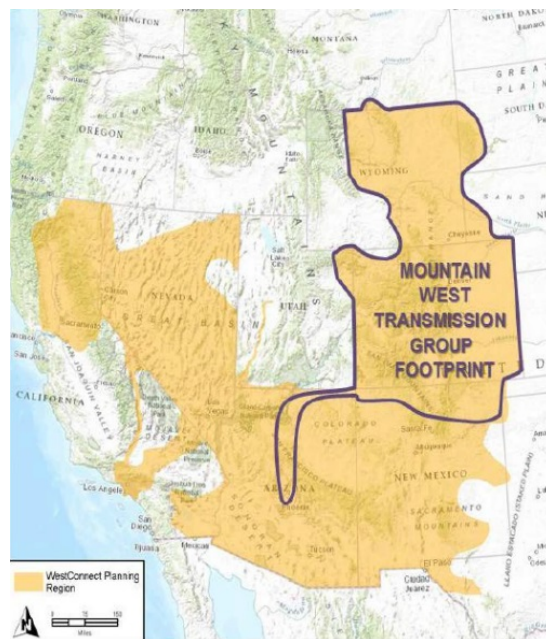
⁵⁰ Xcel (2015).

⁵¹ Xcel (2015).

⁵² CoPUC (2016).

“rate pancaking” – the addition of multiple utilities’ transmission wheeling rates as one moves power across those utilities’ transmission networks – through the Mountain West Transmission Group (MWTG).⁵³ This is in part motivated by wanting to site renewables more optimally and reducing the wheeling charges associated with moving renewable power from a neighboring jurisdiction’s territory.⁵⁴ The MWTG has conducted a cost study to understand how potential costs of a joint tariff could be allocated and is in the process of conducting a production cost study to estimate the benefits of more optimal dispatch across MWTG’s territory with a single tariff. The results of these evaluations are likely to be used in any applications to federal or state regulators in moving forward with developing a joint tariff.

Figure 12: MWTG Service Territory⁵⁵



In addition to a joint tariff, the MWTG is also evaluating the option of an RTO, recognizing that it has become more difficult to optimize the efficiency of the system while maintaining reliability under the ever-changing rules and regulations associated with operating an electric system.⁵⁶ The MWTG issued requests for information from many ISOs and RTOs in the U.S. in May 2016 to better understand the cost estimates on transmission services, ancillary services, planning concepts, interconnection processes, and other topics. This information was used to assess whether MWTG should not only move towards an RTO structure, but also to understand whether it should join an existing market or create a new one.⁵⁷ In January 2017, MWTG announced it was formally entering discussions to potentially join the Southwest Power Pool (SPP).

⁵³ Ibid.

⁵⁴ <https://www.euci.com/mountain-west-transmission-group-pancakes-and-rtos/>

⁵⁵ Bailey (2016).

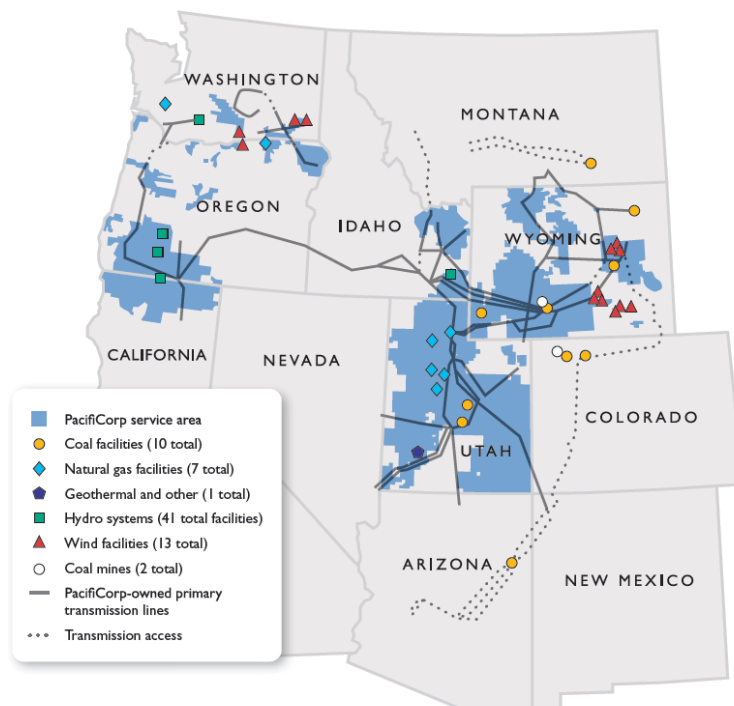
⁵⁶ Bailey (2016).

⁵⁷ Ibid.

3.2.2.2 PacifiCorp

PacifiCorp operated as a vertically integrated utility without participation in centralized markets from its founding in 1910, as Pacific Power, until recently.⁵⁸ PacifiCorp had been participating in, or following, a number of Western U.S. regional coordination efforts that explored access to flexible resources, utilization of existing and new transmission facilities, and use of tools, services, and products to integrate variable generation for many years.⁵⁹ In addition, PacifiCorp's service territory (see Figure 13) has large gaps between the eastern and western portions of their system. Exploring enhanced coordination with neighboring balancing areas likely provided a means to understanding how to improve operations across its own bifurcated service territory. When the CAISO provided a public proposal for an EIM in 2012, leveraging the CAISO's existing real-time market software, PacifiCorp's interest was piqued and it became the first entity to formally explore an EIM with CAISO.⁶⁰

Figure 13: PacifiCorp's Service Territory⁶¹



The EIM is a real-time energy market designed to allow balancing authorities to trade imbalance energy within the hour—practices are unchanged up to the start of the hour. The EIM settles every five and fifteen minutes and use locational marginal prices, which means that prices account for the cost of congestion and losses at specific locations on the system EIM participants are still responsible for the

⁵⁸ <https://www.PacifiCorp.com/about/co.html>.

⁵⁹ Ibid.

⁶⁰ PacifiCorp (2014).

⁶¹ https://www.PacifiCorp.com/content/dam/PacifiCorp/doc/About_Us/Company_Overview/PC-10k-ServiceAreaMap-2016.pdf.

reliability of their systems and the scheduling and dispatch of their resources on a day-ahead and hour-ahead basis. The EIM runs a real-time market optimization across the EIM footprint, removing transmission charges intra-hour to create an optimal dispatch within and across all the participants' service territories. The transition to the EIM was motivated by the changing electricity sector in the Western U.S. which, at the time of PacifiCorp's EIM evaluation in 2013, had renewable portfolio standards in place that were expected to install 60 GW of renewables across the Western U.S. by 2022.⁶² Rising penetrations of solar and wind generation, as demonstrated by the RPS policies in the Western U.S., have underscored the need for more efficient energy imbalance mechanisms because of wind and solar resources' greater variability and uncertainty.⁶³

Determining the value proposition of a regional coordination mechanism to PacifiCorp's system was important because any mechanism that involved potential changes to customers' rates would need to be approved by state regulators in each of the six states that PacifiCorp operated. Regulators would need to understand how the market mechanism impacted customer costs and system reliability, and give their approval before PacifiCorp could enter the regional mechanism. In addition, the creation of a new wholesale market would require approval from FERC. To develop the value proposition, PacifiCorp and CAISO commissioned a study to evaluate the EIM in 2013.⁶⁴

PacifiCorp's evaluation of the EIM focused on changes to the following four system operations: 1) interregional dispatch between PacifiCorp and CAISO; 2) intraregional dispatch within PacifiCorp; 3) flexibility reserve requirements in PacifiCorp and CAISO; and 4) renewable energy curtailment in the CAISO. The study compared a reference case, which assumed current scheduling and operating practices, to an EIM case, where an EIM was established between CAISO and PacifiCorp.⁶⁵ Figure 14 below shows the annual benefit estimate by category in 2017 under various transfer capabilities to both CAISO and PacifiCorp, and Figure 15 shows the portion of benefits attributed to PacifiCorp.

⁶² E3 (2013).

⁶³ GE Energy (2010).

⁶⁴ E3 (2013).

⁶⁵ The dispatch benefits are calculated using production simulation modeling. The PacifiCorp EIM study used the Gridview production simulation model and subsequent EIM studies have used PLEXOS and other custom models.

Figure 14: EIM Estimated 2017 Benefits to CAISO and PacifiCorp

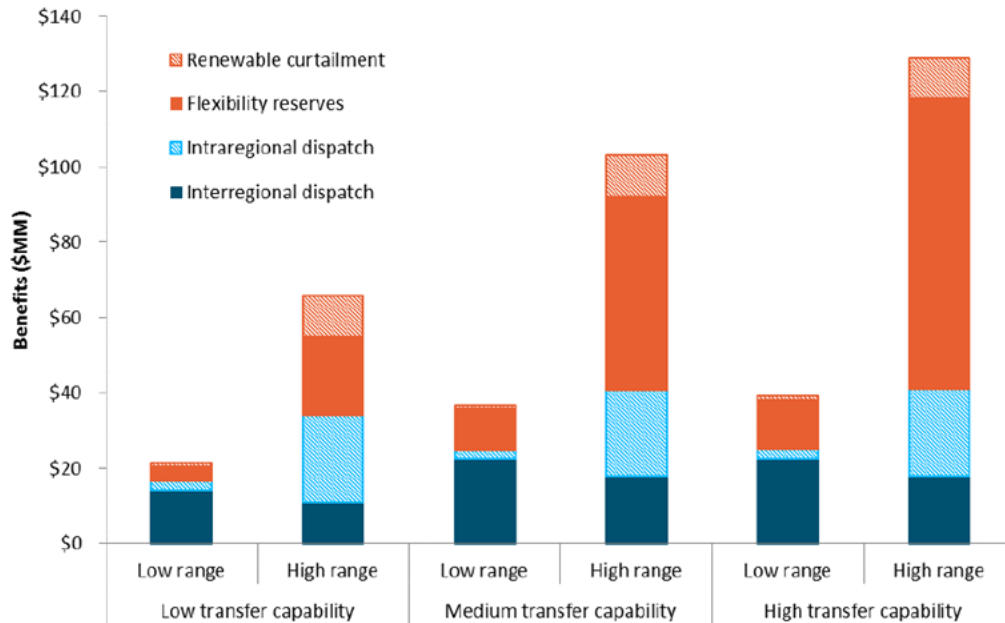


Figure 15: Low and High Range of Benefits Attributed to PacifiCorp in 2017 under a PacifiCorp-CAISO EIM⁶⁶

Benefit Category	Low transfer capability		Medium transfer capability		High transfer capability	
	Low Range	High Range	Low Range	High Range	Low Range	High Range
	Interregional dispatch	\$7.0	\$5.5	\$11.2	\$8.9	\$11.2
Intraregional dispatch	\$2.3	\$23.0	\$2.3	\$23.0	\$2.3	\$23.0
Flexibility reserves	\$1.2	\$6.1	\$3.2	\$14.9	\$3.9	\$22.5
Renewable curtailment	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Total benefits	\$10.5	\$34.6	\$16.7	\$46.8	\$17.4	\$54.4

Note: Attributed values may not match totals due to independent rounding.

The EIM benefits to PacifiCorp ranged from over \$10 million to \$54 million annually. When compared to the cost of entering the EIM, which was estimated to be a one-time startup cost of approximately \$3-\$6 million, which covers the cost of expanding the CAISO’s modeling and systems to include PacifiCorp, and an annual cost of \$2-\$5 million per year, which covers the administrative costs of EIM operations, the benefits were higher than the costs in most scenarios. In addition, entry and exit to the EIM was voluntary, as was providing bids for generators. These non-binding terms and low cost of the EIM start-up provided a low risk set-up for PacifiCorp’s entry into a centralized market. The only thing that changed for PacifiCorp was its real-time operations; all practices remain unchanged up until the start of the hour, which meant PacifiCorp was still in control of forecasting and scheduling for its generation on a forward basis as well as holding their system’s needed operating reserves.

⁶⁶ E3 (2013).

PacifiCorp agreed to join the CAISO's EIM in 2013 and went live with the EIM in the fall of 2014 after the CAISO obtained tariff approval for the EIM from FERC.⁶⁷ Since the EIM went live, the CAISO has reported gross benefits related to the EIM on a quarterly basis. Following PacifiCorp's lead, a number of other utilities have joined the EIM, with the committed members of the EIM currently covering over half the Western U.S.' load.⁶⁸ As of Q3 2016, the CAISO estimated \$114 million in total benefits since the market went live in 2014, with \$15 million of benefits attributed to PacifiCorp in Q3 2016 alone, which was higher than most of the annual benefit estimates from the EIM evaluation.⁶⁹ The CAISO also estimates the amount of reduced renewable curtailment, reduced flexibility reserves, and carbon savings attributable to the EIM in each quarter. These quarterly reports help regulators, EIM participants, and other stakeholders understand the dynamics of the EIM and whether the value propositions estimated in the EIM evaluations hold true.

The success of the EIM for PacifiCorp has motivated it to study full participation in CAISO markets, including participation in the day ahead market. This would not only optimize dispatch across CAISO's and PacifiCorp's footprints on an intra-hour basis as it does in an EIM, but it would also optimize day-ahead unit commitment and conduct hourly merit order dispatch. In addition, PacifiCorp would be subject to participation in the CAISO's transmission planning process and governance. For the evaluation of full participation, there are a number of stakeholder processes in place to review issues such as regional resource adequacy, transmission access charges (TAC), and governance.

Summary:

- Higher penetrations of renewables, along with the availability of low-cost, low-risk regional coordination solutions, have facilitated recent regional coordination successes in the Western U.S.
- Regional coordination solutions must provide open access provisions to be approved by FERC and must show benefits, likely in the form of savings to customers, for state regulator approval.
- Development of a value proposition is important for: (1) internal evaluation for adopting a regional coordination mechanism; and (2) for external purposes such as regulatory approval and stakeholder engagement.
- The success of incremental regional coordination efforts, like joint dispatch and EIM which doesn't change any standard practice up until the start of the hour, provides participants with exposure to market based mechanisms which could facilitate larger and more transformative regional efforts in the future.

⁶⁷ FERC (2014).

⁶⁸ <https://www.caiso.com/Documents/EIMCompanyProfiles.pdf>.

⁶⁹ CAISO (2016).

3.2.3 Increasing Resource Flexibility

Key Questions:

- What is driving the need for increased flexibility in the U.S.?
- What can we learn from coal plant cycling experience in the U.S.?
- How will demand-side programs need to evolve in their design in response to electric systems with higher penetrations of renewables?

Wholesale energy markets have put pressure on coal plants to compete as there has been downward pressure exerted on energy prices through lower fuel costs and exacerbated by increasing penetrations of zero variable cost energy sources like wind and solar. Increasing penetrations of renewable energy on electricity systems throughout the U.S. in the last decade are largely due to renewable energy policy targets and declining renewable technology costs. These economic market signals have led to investments to increase flexibility of existing thermal generation. This landmark change in the makeup of the generation fleet has led to power system flexibility becoming increasingly important to maintain reliable system operations under high penetrations of renewables. In the U.S., a fair amount of research has been completed to understand the impact renewables will have on the long-term adequacy of the grid to meet operational challenges posed by renewables as well as the economics of different flexibility solutions.

As India's generation fleet is largely made up of coal, there is potential to learn from international experience, particularly in the U.S., Western Europe, and China, in operating coal plants in areas with high penetrations of renewables. In addition, there are a number of mechanisms that might be used to harness the flexibility of the demand side, which could be implemented through the right combination of incentives and technologies to help integrate renewables. There is a growing consensus that finding mechanisms to make existing generation and loads more flexible will be a less expensive solution to renewable integration than making larger, capital-intensive investments in flexible generation, storage, or transmission. This section explores examples of coal plant flexibility and demand-side flexibility in the U.S. that may be applicable in an Indian context.

3.2.3.1 *Coal Plant Flexibility*

Most of the U.S. coal generation fleet was built in an era of vertically integrated utilities with the expectation that, with low variable costs, the plants would operate throughout most of the year in a baseload pattern. However, the more recent transition towards deregulated markets has placed competitive pressure on coal plants, which have been forced either to compete on an economic basis or to retire. Especially in the low gas-price environment of the past few years, these competitive circumstances have contributed to the retirement of 18 GW of coal generating capacity between 2015-16.⁷⁰ For those plants that choose to remain in service, making profit in a competitive wholesale market

⁷⁰ <https://morningconsult.com/2016/05/03/coal-plants-shutting-without-clean-power-plan/>

has provided an incentive to explore mechanisms that might allow them to operate more flexibly in order to improve their position in the market.

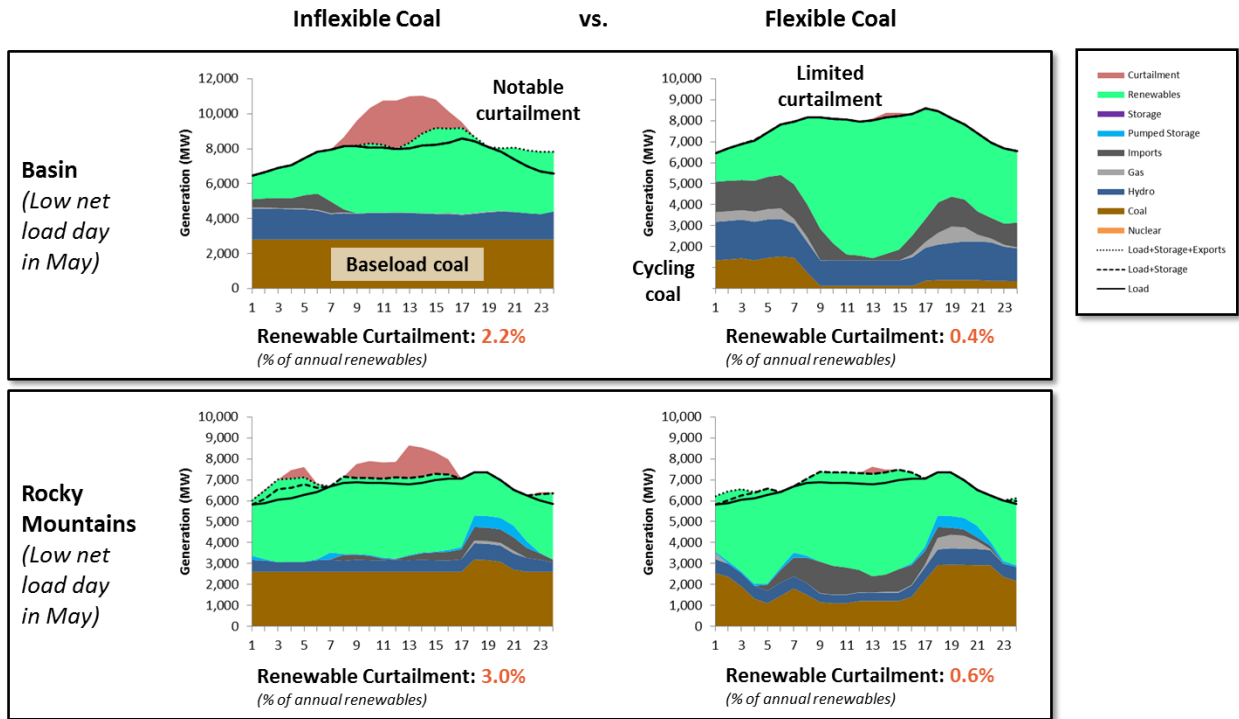
The addition of VRE to the electric system tends to reinforce the incentive to coal generators to improve their operating flexibility – should they choose to remain online – for two reasons: (1) higher penetrations of renewable generation tend to suppress market prices, which lowers the opportunity cost of shutting down during periods of low prices; and (2) wholesale prices tend to become increasingly volatile with higher penetrations of variable energy, which increases the value of cycling and ramping capabilities.

Enabling flexible operations thereby improves the competitiveness of traditionally inflexible coal generators under higher renewable penetrations while also facilitates the efficient integration of higher penetrations of renewable generation. Several recent renewable integration studies have examined how increased flexibility from coal plants contributes to the integration of increasing penetrations of renewable generation; for example:

- The Western Electricity Coordinating Council (WECC) and Western Interstate Energy Board (WIEB) jointly commissioned the Western Interconnection Flexibility Assessment in 2015 to examine the need for operational flexibility at high renewable penetrations. One of the questions investigated by this study was the degree to which increased coal flexibility, namely increased cycling, would reduce the need to curtail renewable generation at a penetration of 40% renewables. Figure 16 illustrates the impact of increased flexibility of coal plant operation on renewable curtailment in two regions in the Western U.S. This is due to a number of flexible coal units turning off in the middle of the day to accommodate solar that would otherwise be curtailed.
- The PJM Interconnection commissioned the PJM Renewable Integration Study in 2014 to study the impacts of renewable penetrations between 15-30% on the PJM system. Among other conclusions, this study observed increases in the frequency and magnitude of coal plant cycling, particularly at 30% renewable penetration. While the costs of cycling to the system are small, the cost of cycling is a large portion of individual generator revenues.⁷¹

⁷¹ GE Energy (2014).

Figure 16: Illustration of Inflexible versus Flexible Coal Operation in the Western U.S., from the Western Interconnection Flexibility Assessment⁷²



Recognizing the potential benefits of transitioning away from the baseload paradigm and operating coal generators more flexibly, several organizations have conducted studies to examine how such improvements in flexibility might be achieved. In a 2013 report by the National Renewable Energy Laboratory (NREL) called “Flexible Coal: Evolution from Baseload to Peaking Plant”, an anonymous coal plant dubbed “CGS” with multiple units in the U.S. was highlighted for its ability to run flexibly, despite being built as a baseload unit whose output was expected to be constant over time.⁷³

The CGS facility was built in the 1970s with the expectation of running at an 80% annual capacity factor. As market dynamics evolved, first with the introduction of nuclear power soon after CGS came online, and later as a competitive market emerged in the early 2000s in CGS’ service territory, CGS’ generation was reduced to a 50% annual capacity factor and the plant was cycled significantly (turned on and off within a day). The main physical issues with cycling and operating at minimum load for CGS and other baseload coal facilities is the wear and tear on equipment and the degradation of plant heat rate due to dynamic operations.⁷⁴ To address the impacts of cycling, CGS made physical modifications after an evaluation of whether the market opportunities in the next year justified the cost of the modification and reduction in the forced outage rate in which the modification resulted. In addition to these physical

⁷² E3 (2016).

⁷³ NREL (2013).

⁷⁴ “The Cost of Cycling Coal Fired Power Plants”, <http://large.stanford.edu/courses/2014/ph240/wolkoff1/docs/cyclingarticles.pdf>

modifications, plant operating procedures were revised to focus on limiting temperature increases on plant start-up, limiting temperature drops on shutdown by monitoring temperature on various parts, developing stringent inspection programs with associated processes for repair, and most importantly, training of the operators to reinforce skills needed to identify the impacts of cycling. These changes combined resulted in significant flexibility improvements. Prior to these modifications, CGS would not run lower than 40%-50% of its rated capacity (P_{min}); with modifications, the plant was able to run at 19% of its rated capacity (within windows of 2-6 hours, the CGS owner could further reduce generation to 7% of rated capacity). This reduction in minimum generation of 20%-30% from standard levels provides an example of how individual coal facilities could ramp down in the middle of the day or night to accommodate large amounts of wind and solar rather than shutting down the facility for multiple days.

While the CGS plant presented in the NREL study is a single example of a completed transition to a flexible operating regime, its experience is shaped by the same circumstances that face most of the U.S. coal fleet: increased competitive pressures, in part due to increasing penetrations of renewable generation, leading to the need to explore measures to increase operational flexibility to remain competitive. Ultimately, this transition to a more flexible and more responsive generation fleet will ease the challenges of renewable integration. Utilities in the U.S. have seen similar transitions in operations of their coal facilities. PacifiCorp recently recounted, during the USAID sponsored training tour to the U.S., that they could operate their coal facilities at 20% of nameplate capacity without any retrofits. This type of operation was motivated by the financial signal the EIM provided their plants. Coal plant operators across the company are now motivated to maximize plant profits by analyzing EIM prices and have accordingly improved plant operations to become more flexible.

The U.S. experience with coal plant flexibility shows that price signals have begun to harness the inherent flexibility in coal plants that was once thought to be technically infeasible. Similar emergence of price signals in India, through regional coordination mechanisms, markets, and regulations, can provide incentives for plants to operate similarly in India.

3.2.3.2 *Demand-side Flexibility*

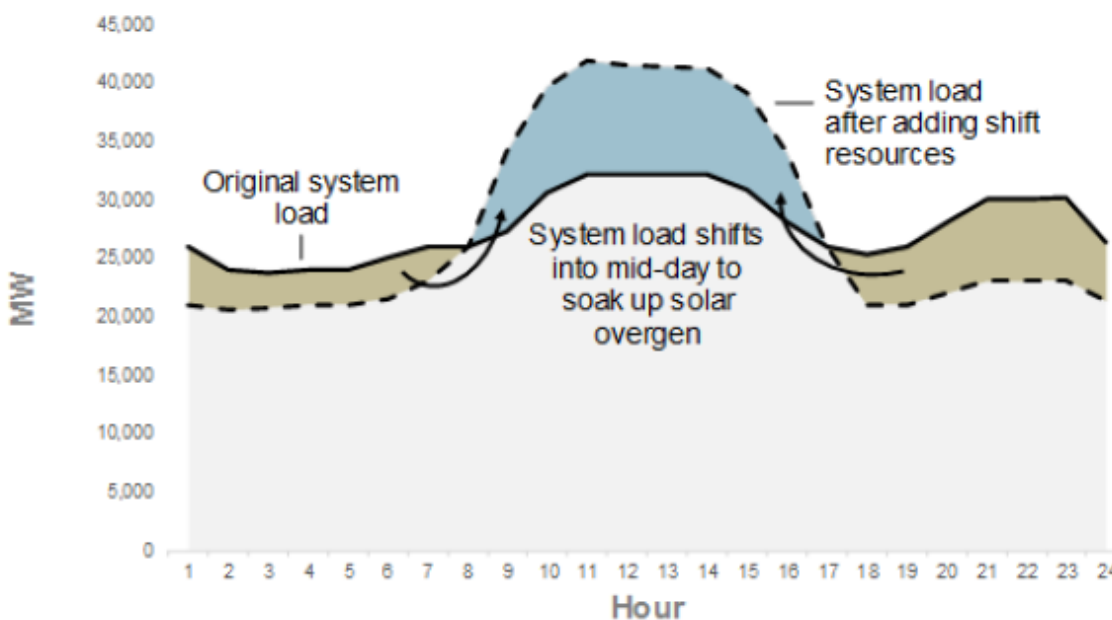
Another area of interest that has received increasing attention in the context of renewable integration is the idea of increasing “demand-side flexibility”—that is, the ability of loads to adjust in response to market signals and changing system conditions in order to help the system balance the intermittency of renewable generation. Historically, there has been little need for such flexibility from the demand side – demand-side programs have typically either focused on reducing peak demand (e.g. demand response, critical peak pricing) or reducing utility load in aggregate (e.g. energy efficiency) – but as the penetration of intermittent resources grow and supply-side generation resources become increasingly constrained in the flexibility of their operations, the idea of harvesting the innate flexibility of loads has attracted interest.

With these changes, regulators, utilities, operators, and market participants have begun to consider expanded options to facilitate demand-side participation. In contrast to traditional demand-side programs that can be called upon only under extreme circumstances to reduce peak, programs that change the hourly profile of energy consumption on a day-to-day basis may offer more value in the

future as the shape of net loads change with growing renewable penetrations. Emerging technologies (e.g. storage, energy management systems) could offer customers new means of directly controlling their consumption patterns, either directly or via an aggregator. At the same time, new types of electric loads (e.g., electric vehicles) could be well-suited to offer more flexibility than traditional end uses. Several states in the U.S., such as New York and Hawai'i, are exploring dynamic retail tariffs to take advantage of demand-side flexibility from distributed energy resources.

A recent study by LBNL and E3 evaluated the types of DR programs that California may need as it moves towards a high renewable future as well as the size and cost of these resources. It found that shift DR, DR that shifts demand from periods of high demand to periods of renewable overgeneration and avoids or reduces ramps, had the most opportunity to provide system level value at up to \$600 million per year.⁷⁵ The value comes from using advanced control technologies to shift ~10% of daily energy within the day. Shifting demand to periods of renewable overgeneration were especially high value because it prevented the capital cost of overbuilding renewables to replace curtailed renewables to meet renewables compliance obligations. Figure 17 below illustrates how a shift DR program would work.

Figure 17: Illustration of Shift DR operations on a high overgeneration day in California⁷⁶



LBNL’s study identified a number of mechanisms that could provide the “Shift” service shown in Figure 17, including changes to HVAC setpoint, customer sited battery storage, industrial process scheduling, electric vehicle charging, refrigerated warehouse scheduling, and water pumping process scheduling. In addition to the advanced control technologies, there are more traditional DR options, such as thermal energy storage, building precooling, and changing patterns of combined heating and cooling use, which

⁷⁵ LBNL (2016).

⁷⁶ Ibid.

could provide the same type of Shift DR services. Though LBNL's study found significant value for Shift DR resources, there is currently no market mechanism to compensate such resources in California. This is true of many jurisdictions: many markets are not set up to allow this level of demand-side participation, nor do utilities have procurement programs focused on these types of resources.

A handful of jurisdictions have implemented DR programs that enable direct load control for customer end uses such as heating and cooling. In Maryland, for example, utilities have access to 677,000 customers' thermostats, central air conditioning, and electric heat pumps, which it can cycle when there are emergency events.⁷⁷ In addition, Maryland utilities have several dynamic retail pricing programs which it bids into the PJM capacity market. These programs cleared at 379 MW in PJM's capacity market for 2018-19. While these types of programs are currently used to reduce system peak, they could be incrementally redesigned to be utilized in the context of renewable integration as discussed above. As the penetrations of renewables continue to increase, it is likely that regulators, utilities, and operators will continue to explore such innovative roles for the demand-side.

In addition to demand side program design, regulations have also enabled the opening of markets to demand side resources. Several federal regulations have tried to remove barriers for demand side resources to participate in wholesale markets, similar to how FERC's open access regulations allowed non-discriminatory access to the transmission system for all generators. FERC Order 755 required wholesale markets to compensate the provision of frequency regulation and remove undue bias in procuring frequency regulation. The payment is based on the service they provide, including separate payments for capacity and performance. This enabled demand side resources, like advanced demand response, to be able to respond to automatic generation control (AGC) signals and be compensated for its services. Similarly, FERC Order 784 reformed ancillary service markets by requiring utilities to evaluate the speed and accuracy of regulation resources when the utility determines its reserve requirements, which demand side resources can often do better than traditional generators.

⁷⁷ PSCM (2016).

Summary:

- Literature suggests that finding ways to make existing generation and loads more flexible is a less expensive way to integrate renewables than investments in new flexible generation, storage, or transmission
- Wholesale energy markets in the U.S. have provided economic signals for coal plants to modify their operations, by either retiring or making flexibility modifications, in response to declining energy prices and changing net load patterns.
- The U.S. has limited experience in demand-side flexibility outside of standard peak reduction measures and energy efficiency. Increased penetrations of renewables have attracted interest in developing more flexible load programs as supply-side resources have become increasingly constrained in the flexibility of their operations.
- Demand-side flexibility programs will need to be redesigned to address the new constraints that emerge in systems with high penetrations of renewables, such as overgeneration.

3.2.4 Clarifying Roles, Responsibilities, and Authority

Key Questions:

- Why did the roles, responsibilities, and authority for various entities develop the way they did in the U.S.?
- Who is responsible for forecasting, scheduling, and balancing under different market structures?
- Where does the division of jurisdiction exist between central and state regulators?

The clear delineation of roles, responsibilities, and authority among the various entities in the power sector is critical to efficient system operations and renewable integration. In the U.S., this delineation has developed with the evolution of the regulation of the interstate electric system. This section discusses the evolution of roles in the electric sector, the delineation of responsibilities for forecasting, scheduling, and balancing among entities in the electric sector, and how regulators in the electric sector interact with entities involved with forecasting, scheduling, and balancing.

As discussed in Section 3.2.1, there was an evolution of access for generators from before the mid-1990s to today. Prior to the mid-1990s, FERC had little jurisdiction over a vertically integrated utility outside of its unbundled transmission rates. State regulators had the most jurisdiction over vertically integrated utilities during this time, overseeing the utility's retail rates, maintenance of system reliability, facilitation of public policy goals, and the investment climate in which the utility participated. With the rise of third party generation through PURPA, however, open access to the transmission system became increasingly important, and FERC issued its landmark Order 888 in 1996 that required all utilities to provide open access to the transmission system, through OATTs, to all parties that requested transmission service. As part of providing open access, Order 888 required utilities to functionally unbundle, meaning that they had to: 1) take transmission service under the same tariff they offer customers; 2) have separate rates for wholesale generation, transmission, and ancillary services; and 3)

use the same electronic information that transmission customers use to get information about their transmission system.⁷⁸ Through its passage, Order 888 also defined a role for FERC to have more jurisdiction over the transmission system as compared to the industry pre-Order 888.

The focus on creating a level playing field for utility owned generation and third party generation facilitated the shift towards competitive markets and obviated a need for an independent, unbiased grid operator. While the ISO and RTO concept naturally grew from the long history of power pools in the U.S., FERC further encouraged the development of RTOs and ISOs to address the continued need for undue discrimination, which it recognized Order 888 alone did not fully address.⁷⁹ As RTOs and ISOs have grown in the U.S. over the last decade (largely outside the Western U.S.), FERC’s role as a regulator has also grown because it has jurisdiction over these wholesale energy markets. While states don’t have direct regulatory authority over ISOs and RTOs, they often bring any complaints or cases directly to FERC when they believe an energy market isn’t operating as it should.

As described in Section 3.2.2, efforts to develop competitive regional markets outside of the CAISO failed many times over in the Western U.S. for a multitude of reasons. To this day, many utilities in the Western U.S. continue to operate their transmission system under functional unbundling and Order 888 compliant OATTs. As noted in Section 3.2.2, however, there is a newfound interest in regional market based mechanisms in the Western U.S. Depending on how far along the spectrum of regional coordination utilities in the Western U.S. move (see Figure 11), the delineation of roles, responsibilities, and authority are ceded to varying extents from the utility to system operator, particularly in the context of forecasting, scheduling, and balancing of generation.

Table 7 below illustrates the entities responsible for forecasting, scheduling, and balancing, and other electric sector services, under various levels of regional coordination, drawing on the case studies in Section 3.2.2. For the purpose of this discussion, the utility for each of the scenarios is denoted in the second row of the table, and forecasting is meant to represent the forecasting of loads and generation on a timescale of a week ahead to real-time basis, rather than longer-term (month ahead). Resource adequacy in Table 7 refers to the responsibility of ensuring there is enough capacity on the system to meet the system load.

Table 7: Allocation of Roles and Responsibilities Across Regional Coordination Mechanisms

	Utility not participating in centralized markets	Utility participating in a joint dispatch service	Utility participating in CAISO EIM	Utility full participation in CAISO day-ahead and real-time markets
Example Utility	PSCo and PacifiCorp prior to joint dispatch service and EIM	PSCo	PacifiCorp (currently)	PacifiCorp (future)
Forecasting	PSCo/PacifiCorp	PSCo	PacifiCorp	CAISO

⁷⁸ FERC (1996).

⁷⁹ FERC (2005).

responsibility				
Scheduling responsibility	PSCo/PacifiCorp	PSCo	PacifiCorp	Utility provides self-schedules and generator availability, CAISO dispatches
Balancing responsibility	PSCo/PacifiCorp	Joint dispatch service operator (PSCo)	EIM operator (CAISO)	Day-ahead and real-time market operator (CAISO)
Transmission planning responsibility	PSCo/PacifiCorp	PSCo	PacifiCorp	CAISO
Resource adequacy responsibility	PSCo/PacifiCorp	PSCo	PacifiCorp	PacifiCorp

As illustrated in Table 7, the level of regional coordination increases (becomes more centralized) as one moves from no participation in centralized markets to full participation in day-ahead and real-time markets (left to right). As the level of regional coordination increases, the more utilities cede their authority in forecasting, scheduling, and balancing to the market operator. The existence of centralized day-ahead and real-time markets, however, does not preclude utilities from engaging in bilateral contracts, which provide price certainty for their power purchases. Bilateral contracts are often hedged in markets through contracts for differences or, in areas with nodal pricing, financial transmission rights.

In a case with a utility that does not participate in any centralized market, the utility is required to perform all the services of forecasting, scheduling, balancing, and other planning processes such as transmission planning and resource adequacy planning. In a joint dispatch or EIM scenario, the utility is responsible for all services required prior to the start of the hour, such as load and generation forecasting, day ahead unit commitment, and hour ahead dispatch. The intra-hour balancing in the joint dispatch and EIM scenarios are handled by the market operator. This is the first instance of a utility ceding responsibility to another party along the regional coordination spectrum. Moving even further on the spectrum of regional coordination to full participation in day-ahead and real-time markets, utilities cede almost all of their forecasting, scheduling, and balancing authority to the market operator. This may provide insight into why the Western U.S. has had success with the regional coordination mechanisms in the middle of the spectrum – joint dispatch service and EIM – as utilities have had to cede the least amount of responsibility.

The time it takes for regional coordination mechanisms to be implemented, and for transition of responsibilities, varies depending on the level of regional coordination and the ability to leverage existing software, market design, governance systems, and general institutional thinking around wholesale markets. The Western EIM, for example, took a little less than two years to go live in 2014 from its evaluation in 2013.⁸⁰ The speed with which this was possible can be attributed to CAISO's

⁸⁰ PacifiCorp (2015).

existing real-time market software, market design, governance principles, and OATT language. The MISO market, on the other hand, took about four to five years to develop its Day 1 market, which covered tariff design, redispatch for congestion relief, ancillary services, and transmission planning. From there, it took another three years to move to competitive energy markets, and another four years to develop an ancillary services market.⁸¹ Because MISO was developing their knowledge base around this for the first time, the transition process took much longer than the CAISO's EIM, where CAISO was already operating a real-time market. These two examples illustrate that there is no simple transition process for regional coordination mechanisms, and that it is highly dependent on the ability to leverage existing tools knowledge.

The process of ceding authority to the system operator is rooted in the governance systems of ISOs and RTOs. Governance defines the matters that ISOs and RTOs have jurisdiction over very clearly. In a transition period, the governance system can define how the transition will happen. For example, the CAISO has been working on a proposal of governance principles for a regional ISO, should PacifiCorp become a full member. The proposal includes the following principles.⁸²

- *Preservation of state authority* – this provides the delineation between federal and state regulatory authority in the context what the regional ISO does not have jurisdiction over. The document includes examples of areas the CAISO will not be involved in, such as retail rate making and permitting approvals for high voltage transmission lines, which squarely fall under states' jurisdiction.
- *Transmission owner withdrawal* – provides the right of any participating transmission owner to withdraw from the ISO
- *Transitional committee of stakeholders and state representatives* – develops a committee made up of one public official from each state in the ISO footprint, as well as members from across the spectrum of stakeholders (e.g., utilities, generators, public interest groups), to oversee governance of the ISO during the transition period
- *Transition period* – outlines how the current CAISO board will transition to a regional ISO board that is made up through a new nomination and appointment method
- *Composition and selection of regional ISO board* – defines the new nomination and appointment method for a regional ISO board member
- *Establishment of a Western States Committee* – this outlines the purview of a new committee that gathers input and feedback on issues that are of interest to all states in the regional ISO footprint.
- *Stakeholder processes and stakeholder participation* – review stakeholder process to ensure wide participation and discuss means and methods that would facilitate this.
- *Requirements for plan to become effective, including Governor's certification* – defines the approvals required from various bodies and regulators to have the governance plan become effective.

⁸¹ <https://www.misoenergy.org/AboutUs/History/Pages/History.aspx>.

⁸² CAISO (2016a).

The first principle clearly draws the line between what state regulators have authority over and what ISO, and by extension FERC, have authority over. The transition principles are important because they set the expectations for new market participants as to what is expected during the market transition and how issues can be resolved during the transition. Similarly, the appointment of board members who oversee the ISO needs to be a clearly defined process so that the motivations behind decision making are independent and transparent.

Another key feature of ISOs and RTOs is that they are afforded a significant amount of latitude to problem solve. This responsibility comes from the fact that ISOs and RTOs have strong governing principles that ensure that there is a system of checks and balances should something not work properly. Joint dispatch service and the Western EIM are two examples of this creative problem solving, where FERC reviewed proposals, rather than prescribe standard regulatory frameworks to follow.

Summary:

- FERC action encouraged the formation and growth of ISOs and RTOs because Order 888 didn't remove all incentives to unduly discriminate against third party generators.
- There is a spectrum of regional coordination mechanisms discussed that each have their own delineation of roles and responsibilities for forecasting, scheduling, and balancing. Full participation in day-ahead and real-time markets moves most of the forecasting, scheduling, and balancing requirements to the system operator. Joint dispatch service and the EIM move the balancing service to the system operator.
- Federal regulators have jurisdiction over all wholesale energy markets. State regulators typically have jurisdiction over retail rates.
- System operators have been given a significant amount of latitude to problem solve.

4 Priority Areas of U.S. Experience with Relevance for India

Drawing on the reviews in Sections 2 and 3, as well as discussions during a study tour of Indian regulators to the U.S.,⁸³ this section maps recent U.S. experience with renewable energy forecasting, scheduling, and balancing to an Indian context. We prioritize elements of U.S. experience that have nearer-term relevance for India, focusing on regional balancing mechanisms.⁸⁴

Although the focus in this primer is on renewable energy forecasting, scheduling, and balancing, regulation of renewable energy policy has important implications for renewable energy scheduling and balancing (see Sections 2.3 and 3.2.1). In India, RPO enforcement is an important tool for supporting the continued development of renewable energy. The regional balancing mechanisms described in this section can encourage efficient balancing and economic dispatch, and more utilization of renewable energy. However, it is worth noting that regional balancing mechanisms alone may not support new investments in renewable energy; other enabling policies, such as enforcement of RPO policies, may be required for that objective (see Section 3.2.1).

As described in Section 3, centralized regional balancing markets are an important recent development in the Western U.S.. Centralized regional balancing is providing a low-cost, low-risk mechanism for utilities in the West to efficiently balance higher penetrations of variable renewable generation.

- **Centralized** refers to the fact that a system operator centrally dispatches generating units;
- **Regional** refers to fact that the system operator centrally dispatches generating units over multiple balancing area authority footprints;
- **Balancing** refers to the fact that the central regional dispatch is limited to intra-hour timescales, or equivalently to redispatch from an hour-ahead schedule.

This definition of ‘balancing’ is intentionally broad. It only requires that balancing, which occurs after gate closure, be distinguished from day-ahead and intra-day scheduling of loads and generation. If hour-ahead loads and generation schedules already replicate the solution from a system-wide least-cost optimization, only deviations from schedules due to forecast error (loads, wind, solar, run-of-river hydro) or outages (generators, transmission equipment) are balanced. If hour-ahead schedules do not reflect this least-cost *system-wide* solution, as may be the case initially if multiple balancing areas create a common balancing mechanism, balancing may also encompass re-dispatch of generation for economic reasons, rather than simply to address imbalances.

In India, centralized regional balancing would likely imply at a minimum that POSOCO and the RLDCs (“centralized”) conduct economic dispatch of generation across states (“regional”) within the hour (“balancing”). Beyond this, there are several different avenues for how centralized regional balancing might be implemented in India, discussed below.

⁸³ As part of this project, a group of delegates from central and state regulatory agencies visited the Western U.S. in February 2017.

⁸⁴ Regional balancing is a subset of regional coordination in power system operations. In this section, we focus on intra-hour balancing, on timescales of 5 minutes to around 70 minutes (gate closure) before the operating hour. We do not focus on longer-term (hour-ahead and longer) generation and transmission scheduling and shorter-term ancillary services (e.g., sub-5-minute frequency regulation).

In the Western U.S., centralized regional balancing is addressing several challenges associated with rising penetrations of variable renewable generation. It is enabling:

- **More efficient management of wind and solar variability and uncertainty** — by aggregating renewable generation across regions, regional balancing reduces intra-hour variability and forecast uncertainty for wind and solar generation.
- **More efficient use of thermal and hydropower generation** — a larger pool of thermal and hydropower generation enables these resources to be used more efficiently for balancing on an intra-hour timescale.
- **More efficient signals for renewable curtailment** — through marginal cost-based regional dispatch, system operators can more economically manage grid congestion.
- **Clearer incentives for coal and load flexibility** — through marginal cost-based pricing, coal units and loads can receive clearer economic signals to provide flexibility.

In other words, centralized regional balancing touches on all four of the priority areas in this primer — economic dispatch, regional coordination, coal and load flexibility, and changes in roles, responsibilities, and authority.

Centralized regional balancing could provide similar benefits in India. Ascertaining the magnitude and state-to-state allocation of these potential benefits would require further exploration. Similarly, regulators, load dispatch centers, and discoms would need to explore and assess potential avenues for the design and implementation of a centralized regional balancing mechanism.

The remainder of this section examines: (1) *key insights*, or lessons learned, from the creation and implementation of centralized regional balancing mechanisms in the Western U.S., as well as additional insights from the study tour; (2) potential *implementation considerations* for India, by walking through how PSCo’s joint dispatch service might be implemented in India; and (3) *design considerations* for centralized regional balancing mechanisms, based on Western U.S. experience.

We selected PSCo’s joint dispatch service as the basis for the example in (2), because joint dispatch represents a kind of balancing mechanism that could be more readily implemented in the Indian context. For instance, joint dispatch does not require the pre-existence of a bid-based real-time market, as would an EIM. As in PSCo, joint dispatch could be a bridge to a more complex real-time market.

4.1 Key Insights from the U.S.

This section identifies key insights from the development of the EIM and joint dispatch (Section 3.2.2) that we believe are most relevant to an Indian context. In addition, it identifies and discusses additional insights from the study tour that are relevant to the broader themes discussed in this primer and to USAID’s Greening the Grid program.

4.1.1 Insights and Considerations for Regional Coordination in India

Multiple approaches to centralized regional balancing are possible. The different designs for the EIM and joint dispatch illustrate that there are multiple approaches to centralized regional balancing. There is, in other words, no “standard” model. Different approaches are suited to different contexts and have different incremental institutional and organizational requirements. For instance, the EIM is an extension of the CAISO’s pre-existing bid-based, real-time nodal market, whereas joint dispatch is a

simpler, incremental alternative better suited to PSCo's initial conditions. In India, a centralized regional balancing mechanism could look very different than either the EIM or joint dispatch.

Broad stakeholder engagement and clear value propositions are important for creating consensus. For both the EIM and joint dispatch, CAISO and PSCo undertook detailed value proposition studies to better understand the benefits and costs to different participants. These studies were then shared with regulators and other stakeholders to create the consensus needed to move forward with design and implementation. In addition, these studies can serve as a benchmark to evaluate the mechanism's actual performance. Both the EIM and joint dispatch cases highlight the need to engage with a broad range of potentially affected stakeholders, such as transmission rights holders, rather than limiting engagement to participating utilities.

Regional balancing can be a low-cost, low-risk step toward deeper regional coordination. A key aspect of both the EIM and joint dispatch are that they only use scheduled generation capacity and unused transmission capacity. As a result, participants do not need to negotiate how to share fixed costs or renegotiate existing generation contracts, and the effort required for new participants to join is relatively small. Although this also means that EIM and joint dispatch benefits are relatively small as a share of total operating costs, the benefits of regional balancing extend beyond real-time balancing. EIM participants, for instance, fully expected that participation in the EIM would help to improve the efficiency of generator scheduling, transmission use, and investment decisions. The EIM also laid the groundwork for discussions on PacifiCorp's participation in the CAISO as a full member, through which it would participate in the CAISO's day-ahead market and transmission planning process.

Pillars for successful implementation include voluntary designs, incremental approaches, information protections, and pilot projects. Voluntary designs — allowing participants (utilities) to enter and exit at their choosing and designating which generating units should participate — can ease participant concerns over having to cede some degree of autonomy and control. Incremental approaches — starting with small, incremental changes to existing practices and institutions — reduce the amount of learning by participants and ease concerns over information asymmetries among participants. Attention to protecting participants' information can ease concerns over the confidentiality of commercially-sensitive information. Proving out the concept through a pilot project, such as creating a regional balancing mechanism across a limited geographic scope, such as a few states in India, can test the efficiency gains from a broader balancing area. This experience can provide a platform of learning for other states to take advantage of should they choose to explore regional balancing mechanisms.

4.1.2 Insights and Considerations for Integration of Large Scale Renewables in India

Dispatch software and automatic generation control (AGC) can minimize system operating costs while maximizing the value of renewable energy. Software has played an important role in economic dispatch in the U.S. Implementing dispatch software in India could enable economic dispatch of both thermal and renewable resources. The software would perform merit order dispatch based on variable cost and curtail resources when economic. Compensation for curtailed resources could be addressed through contracts that are settled outside the market. To test the value of dispatch software and AGC in India, a pilot project that implements dispatch software in a state, along with AGC on several generators

in that state, can show the dispatch cost savings as well as renewable integration benefits (in the form of reduced curtailment) of being able to move to faster and more economic dispatch.

Better renewable and load forecasting can also aid in improved system operations. Reducing the energy imbalance burden, through better forecasting of load and renewable energy, can also help system operators better integrate renewables and operate the grid. Centralized forecasting at a system operator level of both renewables and load in the U.S. has given system operators more visibility over the real-time net load needed to be served by thermal and hydropower resources. This allows operators to better schedule and dispatch thermal and hydropower resources. The rapid expansion of rooftop solar PV has created operational challenges for system operators in the U.S., due to their limited ability to forecast and “see” these resources. In India, as rooftop solar PV grows it is important that proper metering and communication technology is built into interconnection standards so that system operators have better visibility into net loads for balancing purposes. In the U.S., penalties on independent system operators and utilities for reliability violations, such as area control error (ACE) violations, provide an important incentive for improved centralized forecasting. This kind of reliability-based incentive framework may be worth examining in the Indian context.

Coal plant operator training has resulted in increased plant flexibility. The largest improvements to coal plant flexibility were obtained through training of plant operators in both PacifiCorp and Xcel Energy. PacifiCorp found that by showing the financial implications (price signals from the EIM) of certain operational patterns to coal plant operators, operators were more likely to think creatively on how to improve processes to increase plant flexibility and profitability. Peer exchanges between Indian plant operators and U.S. plant operators could facilitate the transfer of knowledge on how to run coal plants in a high renewables power system.

4.2 Implementation Considerations, Using Illustrative Example of Joint Dispatch

Much of the institutional foundation for centralized regional balancing in India already exists. For instance, the *Ancillary Services Operations Regulation* enables POSOCO to dispatch central generation units within the hour on a merit order basis to respond to specified events. SLDCs already submit hourly load forecasts and generator schedules information to RLDCs. Some of the institutional and organizational changes required to implement centralized regional balancing in India are thus relatively minor, whereas others would be more significant.

To help illuminate the kinds of considerations for implementing centralized regional balancing in India, it is instructive to think through how PSCo’s joint dispatch service might be implemented at a regional level in India. This example is for illustrative purposes only; it is not intended to be a recommendation. As the next section describes, there are a number of potential options in the design of such a centralized regional balancing mechanism.

In this hypothetical example, all interstate generators would participate in the balancing pool. Power plant owners would select which of their intrastate generators would participate. All participating thermal generator owners would regularly submit cost information to the RLDCs, including heat rate curves and a fuel price, through a web portal. This information would be the basis of the RLDC’s real-time dispatch.

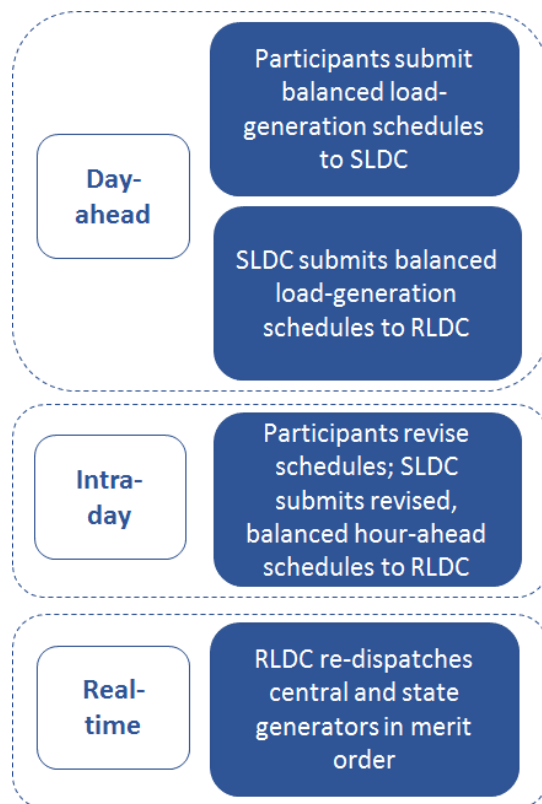
The current practice of SLDC and RLDC coordination with respect to day-ahead scheduling on a day-ahead and intra-day basis would continue largely intact. SLDC schedules could be, but need not be,

based on a merit order, according to variable costs. SLDCs would aggregate balanced day-ahead load and generator schedules from scheduling entities — discoms, exchanges, third parties — and submit these to the RLDC. Throughout the day, participants would submit revised schedules to the SLDCs, based on updated load and renewable energy forecasts, short-term procurement, and changes in generator status. The SLDCs would then submit these updated schedules to the RLDC on a regular basis. These intra-day schedule revisions may require changes to current practice.

As with longer-term and intra-day contracting in PSCo, the role of the power exchanges in facilitating day-ahead and intra-day transactions would be unaffected. That is, discoms and open access customers could continue to use the power exchanges to procure power and adjust their balanced schedules on a day-ahead and intra-day basis.

Scheduling entities would be required to submit balanced hour-ahead schedules. An hour before the operating hour, no further schedule revisions would be permitted. Figure 18 shows a high-level illustration of this scheduling and balancing process.

Figure 18. Hypothetical Process for Scheduling and Balancing under a Centralized Regional Balancing Mechanism in India



Within the hour, the RLDC would dispatch interstate and participating intrastate generators in merit order every 15-minutes to balance regional generation and load. As with PSCo’s joint dispatch, the RLDC’s dispatch would use security constrained economic dispatch (SCED) software and an automated dispatch system (ADS) integrated into an energy management system (EMS) to facilitate dispatch. The RLDC’s intra-hour dispatch could be limited to least-cost balancing of regional deviations from hour-ahead schedules, or it could encompass a least-cost optimization of the entire regional system as in

PSCo.⁸⁵ The RLDC would only use available transmission capacity, and no additional charges would be assessed for transmission use. Line losses associated with joint dispatch energy would be assessed on generators and discoms on the basis of actual energy flows across transmission systems.

For interstate generators and participating intrastate generators the DSM framework would be replaced by a combination of charges and payments through the centralized regional balancing mechanism and penalties for unbalanced schedules.⁸⁶ That is, intra-hour deviations from schedules would be charged or compensated at system marginal cost and settled on a 15-minute basis through the balancing mechanism. Scheduling entities — discoms, exchanges, third-parties — would pay a penalty for unbalanced hour-ahead schedules.⁸⁷ This penalty would be based on some multiple of the RLDC's incremental costs.

Responsibilities for grid reliability, including frequency regulation and contingency management, could reside with the SLDCs or be shared at an RLDC level, as provided for in the *Ancillary Services Operations Regulation*. In either case, units providing regulation or contingency reserves would be identified and scheduled before an hour-ahead timeframe. This approach to providing reserves would likely require an approach to setting reserve levels on a day-ahead timeframe, consistent with a unit commitment time horizon. If reserves are provided regionally, it would also likely require an allocation mechanism to allocate reserve costs to states (e.g., based on the share of regional coincident peak), as well as a settlement platform to collect costs from loads and use them to pay generators. The determination and scheduling of reserves would be separate from the centralized regional balancing mechanism.

For the balancing mechanism, settlement would be based on 15-minute system marginal cost and deviations from schedules. For instance, if a discom's real-time load exceeded its schedule by 100 MW on average during an hour (four 15-minute blocks) when the average system marginal cost was 4 Rs/kWh, that discom would be charged Rs 400,000. The generator providing the additional 100 MWh in that hour would be paid 4 Rs/kWh, or Rs 400,000. The RLDC would no longer need to maintain a DSM pool. Settlement would be automated and maintained in online accounts, with one-week to two-week settlement periods. As in PSCo's joint dispatch, the rationale for this "net zero,"⁸⁸ software-based approach would be to simplify accounting and settlement.

Settlement at system marginal cost will create economic transfers among states, generators, and customers. For instance, consider a situation in which Gujarat has a 100 MW real-time deviation from schedule that it would otherwise meet with an intrastate 5 Rs/kWh generator. Under the regional balancing mechanism, for example, 50 MW of this deviation might be met by a 2 Rs/kWh intrastate generator in Maharashtra, and the remaining 50 MW might be met by a 4 Rs/kWh intrastate generator in Madhya Pradesh. The system marginal cost is 4 Rs/kWh. Gujarat pays 200,000 Rs each to generators

⁸⁵ Optimization based on deviations is, in some ways, more difficult to implement. The RLDC would need to identify eligible kinds of schedule deviations for renewable and conventional generation to include in the optimization constraints. Deviation in generation would be limited to eligible deviations in generation plus deviations in load.

⁸⁶ For non-participating intrastate generators in states that have ratified the ABT, the DSM framework could, in principle, continue to exist in parallel. However, these costs are unlikely to be

⁸⁷ This penalty could be assessed on generators as well, based on the difference between a day-ahead scheduled quantity and an hour-ahead quantity.

⁸⁸ "Net zero" implying that all balancing charges to one party are payments to another party.

in Maharashtra and Madhya Pradesh, but customers in Gujarat save Rs 100,000 by avoiding the need to run the 5 Rs/kWh generator. The generator in Maharashtra earns a net income of Rs 100,000.

For wind and solar generation, deviations from 15-minute forecasts would be settled at system marginal cost. The offtakers for these contracts (discoms, open access customers), which submit wind and solar forecasts as part of their scheduling requirements to SLDCs or RLDCs, pay charges for deviation below forecast or earn revenues for deviations above forecast.

To ensure that participants are not gaming this balancing mechanism to earn excessive rents, CERC caps the system marginal price using an administratively set benchmark price. CERC oversees the mechanism, but both CERC and SERCs have the ability to examine and audit submitted generator cost information or dispatch results.

The cornerstone of a regional centralized balancing mechanism would be a well-functioning system of scheduling, accounting, metering, and settlement, as described in the SAMAST report. For instance, the ability to accurately measure deviations from hour-ahead schedules would require a comprehensive metering infrastructure. Software and automation would also play an important role in facilitating this balancing mechanism. Software would be used for the SCED and automating dispatch. It would be used to automate accounting and settlement for the balancing mechanism. Remote metering (telemetry) could be used to measure generator output in real-time for settlement purposes.

4.3 Design Considerations

The thought experiment above is only intended to be illustrative. At many of the stages in the above example there are competing design choices. For instance, participation could be voluntary or mandatory. Additionally, settlement might be based on shadow prices (system marginal cost) from optimization software, as in the above example, on submitted generator costs, or on the basis of supply and demand bids. These different options have different implications for the allocation of benefits and costs.

Table 8 shows a high-level summary of potential design considerations for a centralized regional balancing mechanism. This list is intended to be illustrative rather than exhaustive.

Table 8. Potential Design Options and Tradeoffs for Centralized Regional Balancing Mechanisms

Area	Design Options and Tradeoffs	
Participation options	Voluntary. Voluntary participation can build trust, enable flexibility, and reduce barriers to participation.	Mandatory. Mandatory participation can improve liquidity and reduce the potential for market power.
Software and control requirements	Lower. Less sophisticated software can reduce lead time for setting up mechanism and learning requirements for system operator staff.	Higher. SCED, EMS, and ADS can reduce the need for manual re-dispatch of units and facilitate quicker dispatch.

Degree of centralization	Lower. Centralized regional dispatch is only limited to imbalances from hour-ahead schedules.	Higher. Centralized regional dispatch re-dispatches all participating, scheduled units to meet demand at least cost.
Offer format	Cost-based. Cost-based offers provide a “paper trail” that can be audited.	Bid-based. Bid-based offers are more flexible and better reflect short-term costs and opportunity costs.
Balanced schedule requirement	Balanced. Reduces the risk of resource insufficiency and the potential for market power.	Partially balanced. Provides more flexibility to load serving entities.
Operating reserves	Decentralized. Participants can secure their own regulation and contingency reserves and retain autonomy in setting reserve levels.	Centralized. Participants can share reserves and pool reserve sharing requirements.
Balancing authority	Decentralized. Enabling local system operators to continue to act as balancing area authorities provides greater state autonomy and control.	Centralized. Centralized real-time (sub-5-minute) operations may increase reliability.
Settlement mechanism	Cost-based. May limit rents to participating generators.	Uniform clearing price. Pricing and savings allocation mechanism are transparent.
Dispatch and settlement interval	Longer. Simpler to manage dispatch and settlement on longer time intervals.	Shorter. Dispatch and settlement on 15-minute and shorter intervals is more efficient, particularly with higher wind and solar penetrations

U.S. experience has shown that design choices are in most cases context specific. The EIM and joint dispatch, for instance, seek to achieve similar goals, but with very different designs that stem from different initial conditions. In practice, design choices must balance efficiency, implementation cost, effectiveness, fairness, and other stakeholder concerns. As evidenced by nearly two decades of experience in U.S. RTO/ISO markets, mechanism designs will continue to evolve over time.

5 References

Bailey, Rodney. 2016. *Mountain West Transmission Group*. Available at: <https://www.wapa.gov/About/the-source/Documents/2016/0928-MWTG-update.pdf>.

California Independent System Operator (CAISO). 2010. *Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS*. Available at: <http://www.uwig.org/CAISO-20PercentRPS.pdf>.

California Independent System Operator (CAISOa). 2016. Second Revised Proposal of Principles for Governance of a Regional ISO. Available at: <https://www.caiso.com/Documents/PrinciplesForGovernanceofaRegionallISO-Clean.pdf>.

California Independent System Operator (CAISOb). 2016. Western EIM Benefits Report Third Quarter 2016. Available at: http://www.caiso.com/Documents/ISO-EIMBenefitsReportQ3_2016.pdf.

Central Electricity Authority (CEA). 2013. *Large Scale Grid Integration of Renewable Energy Sources - Way Forward*. Available at: http://cea.nic.in/reports/others/ps/pspa1/large_scale_grid_integ.pdf.

Central Electricity Regulatory Commission (CERC). 2016. *Deviation Settlement Mechanism and Related Matters (Third Amendment) Regulations*. Available at: <http://www.cercind.gov.in/2016/regulation/SOR123.pdf>.

CERC. 2015a. *Proposed Framework for Forecasting, Scheduling & Imbalance Handling for Renewable Energy (RE) Generating Stations Based on Wind and Solar at Inter-State Level*. Available at: http://cercind.gov.in/2015/draft_reg/frame.pdf.

CERC. 2015b. *Framework on Forecasting, Scheduling and Imbalance Handling for Variable Renewable Energy Sources*. Available at: <http://www.cercind.gov.in/2015/regulation/SOR7.pdf>.

CERC. 2015c. *Ancillary Services Operations Regulations*. Available at: http://www.cercind.gov.in/2015/draft_reg/draft%20cerc%20ancillary%20services%20operations%20regulations.pdf.

CERC. 2015d. *Deviation Settlement Mechanism and Related Matters (Third Amendment) Regulation*. Available at: http://www.cercind.gov.in/2015/draft_reg/Public_Notice2315.pdf.

CERC. 2014. *Deviation Settlement Mechanism and Related Matters Regulation*. Available at: <http://www.cercind.gov.in/2014/regulation/gaz132.pdf>.

CERC. 2010a. *Indian Electricity Grid Code*. Available at: http://cercind.gov.in/2010/ORDER/February2010/IEGC_Review_Proposal.pdf.

CERC. 2010b. *Unscheduled Interchange Charges and Related Matters Regulations*. Available at: http://www.cercind.gov.in/Regulations/UI_Amendments_regulations_2010.pdf.

CERC. 2004. *Open Access in Inter-state Transmission Regulations*. Available at: <http://www.cercind.gov.in/31012004/finalregulations-openaccess.pdf>.

U.S. Department of Energy (DOE). 2007. *Economic Dispatch of Electric Generation Capacity: A Report to Congress and the States Pursuant to Sections 1234 and 1832 of the Energy Policy Act of 2005*.

Washington, D.C.: U.S. DOE. Available at:

https://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/final_ED_03_01_07_rev2.pdf.

Energy and Environmental Economics (E3). 2013. *PacifiCorp-ISO Energy Imbalance Market Benefits*. San Francisco: E3. Available at:

<https://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf>.

Energy and Environmental Economics (E3). 2016. *Western Interconnection Flexibility Assessment*. San Francisco: E3. Available at:

https://www.wecc.biz/Administrative/E3_WECC_WIEB_FlexAssessment_2016-01-27.pdf.

EnerNex Corporation. 2011. *Eastern Wind Integration and Transmission Study: Executive Summary and Project Overview*. NREL/SR-5500-47086. Golden, CO: NREL. Available at:

<http://www.nrel.gov/docs/fy11osti/47086.pdf>.

Federal Energy Regulatory Commission (FERC). 1996. *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities*. Available at:

<https://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-8-00w.txt>.

Federal Energy Regulatory Commission (FERC). 2014. *Order Conditionally Proposed Tariff Revisions to Implement Energy Imbalance Market*. Available at:

<https://www.ferc.gov/whats-new/comm-meet/2014/061914/E-4.pdf>.

Federal Energy Regulatory Commission (FERC). 2016. *Order Accepting Joint Dispatch Agreement and Tariff Revisions*. Available at:

<https://www.ferc.gov/whats-new/comm-meet/2016/021816/E-5.pdf>

Forum of Regulators (FOR). 2015. *Model Regulations on Forecasting, Scheduling and Deviation Settlement of Wind and Solar Generating Stations at the State Level*. Available at:

<http://www.forumofregulators.gov.in/Data/study/MR.pdf>.

GE Energy. 2010. *Western Wind and Solar Integration Study: Executive Summary*. NREL/SR-550-47781. Golden, CO: NREL. Available at: <http://www.nrel.gov/docs/fy10osti/47781.pdf>.

GE Energy. 2014. *PJM Renewable Integration Study*. Available at:

<http://www.pjm.com/committees-and-groups/subcommittees/irs/pris.aspx>.

GIZ-India. 2015. *Report on Forecasting, Concept of Renewable Energy Management Centres and Grid Balancing*. Berlin: GIZ. Available at: <http://mnre.gov.in/file-manager/UserFiles/draft-report-fscb-remcs.pdf>.

Heeter, Jenny, Ravi Vora, Shivani Mathur, Paola Madrigal, Sushanta K. Chatterjee, Rakesh Shah. 2016. *Wheeling and Banking Strategies for Optimal Renewable Energy Deployment: International Experiences*. NREL/TP-6A20-65660. Golden, CO: NREL. Available at: <http://www.nrel.gov/docs/fy16osti/65660.pdf>.

International Energy Agency (IEA). 2015. *India Energy Outlook*. Paris: IEA/OECD. Available at: http://www.worldenergyoutlook.org/media/weowebiste/2015/IndiaEnergyOutlook_WEO2015.pdf.

Lawrence Berkeley National Laboratory (LBNL). 2016. *Final Report on Phase 2 Results: 2015 California Demand Response Potential Study*. Available at: <http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451541>

Loutan, Clyde. 2016. "Briefing on using renewables to integrate renewables." Presentation at the Board of Governors Meeting, December 14-15. Available at: http://www.caiso.com/Documents/Briefing_UsingRenewables_IncorporateRenewables-Presentation-Dec2016.pdf.

Mai, Trieu, Debra Sandor, Ryan Wisser, and Thomas Schneider. 2012. *Renewable Electricity Futures Study: Executive Summary*. NREL/TP-6A20-52409-ES. Golden, CO: NREL. Available at: <http://www.nrel.gov/docs/fy13osti/52409-ES.pdf>.

Milligan, Michael and Brendan Kirby. 2007. *Impact of Balancing Areas Size, Obligation Sharing, and Ramping Capability on Wind Integration*. NREL/CP-500-41809. Golden, CO: NREL. Available at: <http://www.nrel.gov/docs/fy07osti/41809.pdf>.

Milligan, Michael, Brendan Kirby, and Stephen Beuning. 2010. *Combining Balancing Areas' Variability: Impacts on Wind Integration in the Western Interconnection*. NREL/CP-550-48249. Golden, CO: NREL. Available online at: <http://www.nrel.gov/docs/fy10osti/48249.pdf>.

Ministry of Power (MoP). 2016. *Report of the Technical Committee on Large Scale Integration of Renewable Energy, Need for Balancing, Deviation Settlement Mechanism (DSM) and Associated Issues*. New Delhi: MoP. Available at: http://powermin.nic.in/sites/default/files/uploads/Final_Consolidated_Report_RE_Technical_Committee.pdf.

North American Electric Reliability Corporation (NERC). 2015. *Essential Reliability Services Task Force Measures Framework Report*. Atlanta: NERC. Available online at: <http://www.nerc.com/comm/Other/essntlrbltysrvscstskfrcdl/ERSTF%20Framework%20Report%20-%20Final.pdf>.

NITI Aayog, CII, Shakti Foundation, and Regulatory Assistance Project (RAP). 2015. *Report on India's Renewable Electricity Roadmap*. New Delhi: NITI Aayog. Available at: http://niti.gov.in/writereaddata/files/document_publication/Report_on_India%27s_RE_Roadmap_2030_full_report-web.pdf.

PacifiCorp. 2014. *Application for Deferred Accounting and Prudence Determination*. Available at: https://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/Oregon/Regulatory_Filings/Docket_UM_1689/04-18-14_Application_and_Direct_Testimony/application/2_Application_EIM.pdf

PacifiCorp. 2015. *Energy Imbalance Market Partnership*. Available at: http://www.PacifiCorp.com/content/dam/PacifiCorp/doc/About_Us/Energy_Imbalance_Market/Energy_ImbalanceMarketPartnershipFASTFACTS.pdf

Parsons, Brian, Michael Milligan, J Charles Smith, Edgar DeMeo, Brett Oakleaf, Kenneth Wolf, Matt Schuerger, Robert Zavadil, Mark Ahlstrom, and Dora Yen Nakafuji. 2006. *Grid Impacts of Wind Power Variability: Recent Assessments from a Variety of Utilities in the United States*. NREL/CP-500-39955. Golden, CO: NREL. Available at: <http://www.nrel.gov/docs/fy06osti/39955.pdf>.

Public Service Commission of Maryland (PSCM). 2016. *The EmPOWER Maryland Energy Efficiency Act Standard Report of 2016*. Available at: <http://www.psc.state.md.us/wp-content/uploads/2016-EmPOWER-Maryland-Energy-Efficiency-Act-Standard-Report.pdf>.

Public Utilities Commission of the State of Colorado (CoPUC). 2016. *Recommended Decision of ALJ Mana L. Jennings-Fader Granting Application in Part, Addressing Treatment of the Joint Dispatch Agreement, Ordering Accounting Treatment and Ordering Public Service to File Reports*. Available at: https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=854601&p_session_id=

Rajasthan Electricity Regulatory Commission (RERC). 2016. *RERC Forecasting, Scheduling, Deviation Settlement and Related Matters of Solar and Wind Generation Sources Regulations*. Available at: <http://rerc.rajasthan.gov.in/cnpl/PDFs/F&S%20Regulations.pdf>.

Tamil Nadu Electricity Regulatory Commission (TNERC). 2016. *Tamil Nadu Electricity Regulatory Commission Forecasting, Scheduling, Deviation Settlement and Related Matters of Wind and Solar Generation Sources Regulations*. Available at: <http://www.tnerc.gov.in/regulation/draft%20regulations/2016/Forecast-solar%2013-1-2016-Draft.pdf>.

Xcel Energy (Xcel). 2015. *Proposed Tariff Revisions for Joint Dispatch Transmission Service*. Available at: <https://www.xcelenergy.com/staticfiles/xcel/PDF/Regulatory/10-30-2015-Joint-Dispatch-Service-Round-2-Filing.pdf>.

Xcel Energy (Xcel). 2016. *Open Access Transmission Tariff*. Available at: http://www.oasis.oati.com/PSCO/PSCODOCS/Xcel-Energy_OATT_02-10-2016.pdf.

6 Appendix: Background on India's Electricity Sector, Renewable Energy Goals, and Interstate Regulations

6.1 Organization of India's Electricity Sector

India's electricity sector encompasses a large and diverse group of ministries, regulators, grid operators, and generating companies. At the national level, the Ministry of Power (MoP) sets national electricity policy and oversees the overall development of the sector. Within MoP, the Central Electricity Authority (CEA) advises the central government on policy, planning, and technical issues and sets technical standards. The Ministry of Nonconventional and Renewable Energy (MNRE) is responsible for encouraging the deployment of renewable energy.

The Electricity Regulatory Commissions Act (1998) created independent national and state regulators for the electricity sector, whose powers and functions are specified in the 2003 Electricity Act. At the national level, the Central Electricity Regulatory Commission (CERC) regulates licenses and tariffs for generation and transmission used in interstate power exchange, and advises the central government on a range of policy issues. At the state level, State Electricity Regulatory Commissions (SERCs) regulate licensing, wholesale and retail tariffs, interconnection, and standards. The 2003 Electricity Act created an additional set of planning agencies, the Regional Power Committees (RPCs), to facilitate the integration of regional grids.⁸⁹

The 2003 Electricity Act established a multi-tier system of state, regional, and national dispatch centers. The Act designated State Load Dispatch Centers (SLDCs) as balancing area authorities, with responsibility for monitoring and control of state electricity grids. Five Regional Load Dispatch Centers (RLDCs) coordinate scheduling of generation and transmission between states and monitor regional grid conditions. A National Load Dispatch Center (NLDC) manages connections among regional grids and coordinates among RLDCs. The RLDCs and NLDC are part of Power System Operation Corporation, Ltd. (POSOCO), which is a subsidiary of Power Grid Corporation of India (POWERGRID).

Unlike many other countries of its size, since December 31, 2013 India has a national power grid that is synchronized across regions — that is, the five regional grids are connected into a national grid and operate at a single grid frequency. By the end of 2017, POWERGRID anticipates that interregional transmission capacity will reach 65 gigawatts (GW), facilitating significant power flows across grid regions.⁹⁰

Transmission, distribution, and generation in India's electricity sector is owned and operated by a mix of central government, state government, and private corporations. In some states, grid corporations combine state transmission utilities (STUs), distribution companies (discoms), and the SLDC. In other states, these organizations are separated. POWERGRID, the central transmission utility (CTU), owns and operates the interstate transmission system (ISTS).

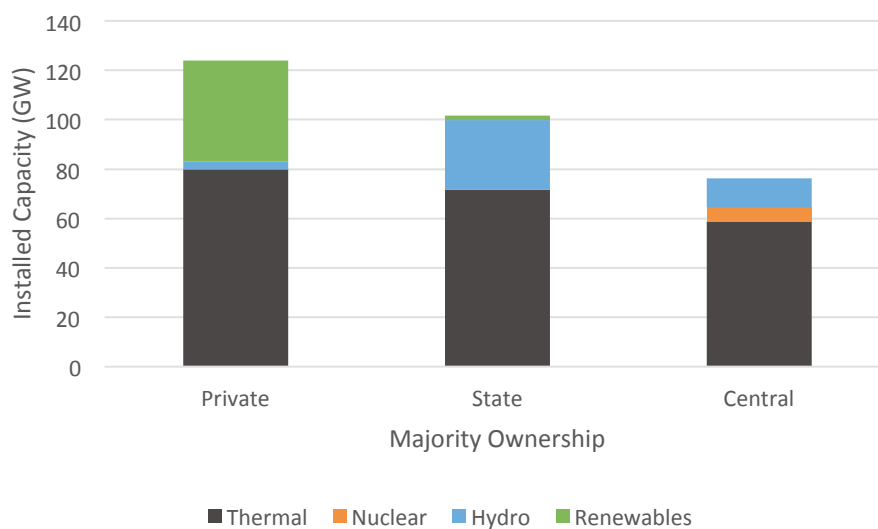
⁸⁹ RPC functions are detailed in the Indian Electric Grid Code (CERC, 2010).

⁹⁰ See POWERGRID, "One Nation-One Grid,"

http://www.powergridindia.com/_layouts/PowerGrid/User/ContentPage.aspx?Pid=78&LangID=English.

Generation ownership is divided among central government majority-owned,⁹¹ state government majority-owned, and private sector companies. As Figure 19 shows, private ownership accounts for the largest share (41%) of generation capacity, followed by states (34%), and the central government (25%). Increases in private ownership have been driven in part by the expansion of renewable energy, which is mostly owned by the private sector.

Figure 19. Private, State Government, and Central Government Ownership of Generation Capacity by Resource Type, 2016⁹²



Generation that is scheduled across states is governed by interstate regulations, whereas generation that is only utilized within states is governed by intrastate regulations. In practice, interstate generation capacity is often owned by central government corporations and is allocated across multiple states. State grid companies have rights to schedule that generation to meet local demand.

India has two national power exchanges — the Indian Energy Exchange (IEX) and Power Exchange India Limited (PXIL) — both of which were established in 2008. These exchanges enable load serving entities, traders, and generators to meet residual needs for power on an intra-day, day-ahead, and weekly basis, and also trade renewable energy credits (RECs). The exchanges complement longer- and shorter-term over-the-counter (OTC) contracts. These bilateral and exchange markets are facilitated by non-discriminatory access requirements for interstate transmission as stipulated in CERC’s 2004 *Open Access in Inter-state Transmission Regulations*.⁹³

⁹¹ Central government firms include the National Thermal Power Corporation Limited (NTPC), the National Hydroelectric Power Corporation (NHPC), and the Nuclear Power Corporation of India Limited (NPCIL).

⁹² Data are from CEA, http://www.cea.nic.in/reports/monthly/installedcapacity/2016/installed_capacity-03.pdf.

⁹³ CERC (2004).

6.2 Renewable Energy Development in India

Renewable energy, and particularly wind and solar energy, has the potential to play a major role in India's energy mix. Renewable generation capacity in India is set to rapidly expand over the next decade, driven by aggressive national and state targets, declines in cost, and alignment with development and energy security goals.⁹⁴ As in other countries, expansion and integration of renewable energy are presenting new challenges in India.

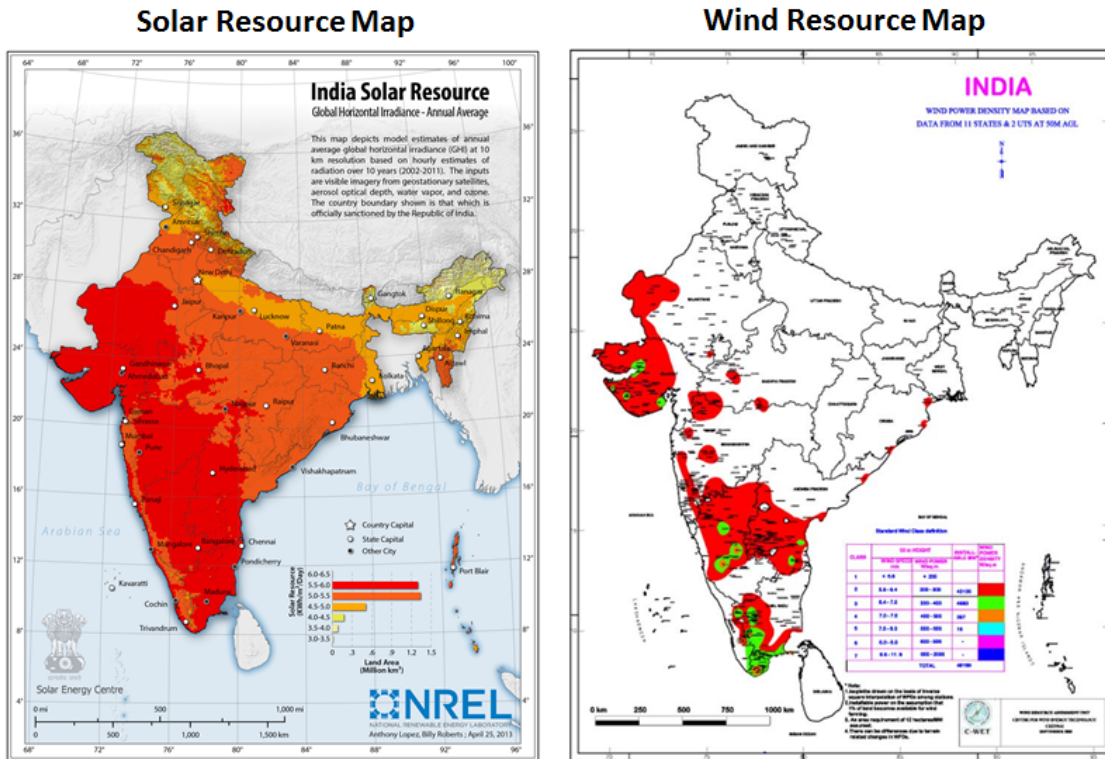
India's two most plentiful renewable energy resources are wind and solar. Wind resource potential, estimated at just over 300 gigawatts (GW) at 100-meter height, is concentrated in western and southern states.⁹⁵ Solar resource potential, approximately estimated at 750 GW,⁹⁶ is more evenly distributed throughout the country, though solar irradiance is generally higher in the western, southern, and northernmost states.

⁹⁴ See, for instance, IEA (2015).

⁹⁵ Data are from the Ministry of New and Renewable Energy (MNRE), "State wise % of Wind Potential Utilized (As on 31.03.2016)," <http://mnre.gov.in/file-manager/UserFiles/State-wise-wind-power-potential-utilized.pdf>. Estimates of wind potential in India vary significantly (IEA, 2015).

⁹⁶ This estimate is from India's National Institute of Solar Energy, cited from IEA (2015).

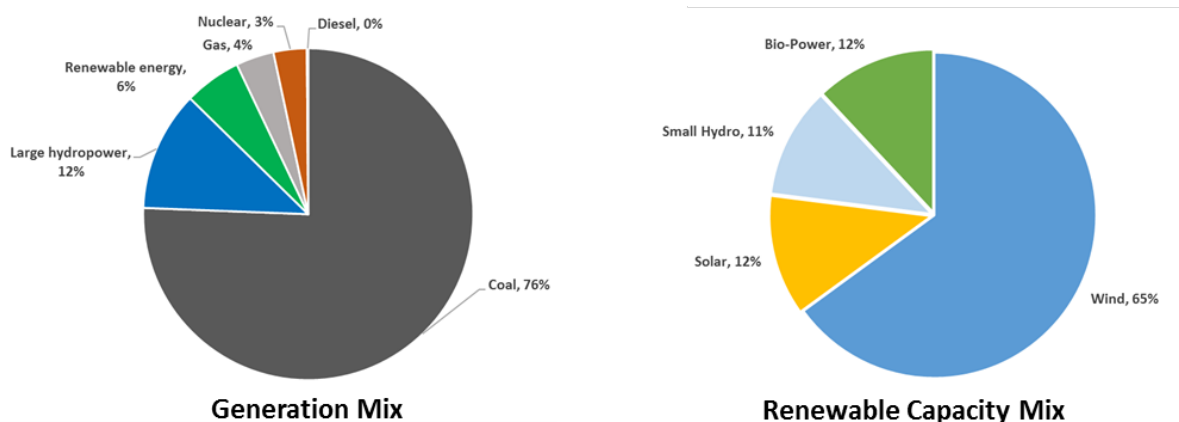
Figure 20. India Wind and Solar Resource Maps⁹⁷



In 2015, renewable energy — biomass, small-scale hydroelectric, solar, and wind energy — generated about 6% of India’s total electricity. Wind was the dominant resource, accounting for more than half (65%) of total renewable generation capacity (Figure 21). Coal (76%) and large-scale hydropower (12%) remain the country’s dominant generation sources.

⁹⁷ Solar resource map is based on annual average global horizontal irradiance, and is from U.S. National Renewable Energy Laboratory (NREL), “India Solar Resource Maps & Data (updated March 2016),” http://www.nrel.gov/international/ra_india.html. Wind resource map is from the Indian Wind Energy Association, www.inwea.org.

Figure 21. Composition of India’s Electricity Generation and Renewable Energy Generation Capacity in 2015⁹⁸



In 2015, the Government of India set a target of installing 175 GW of renewable energy nationwide by 2022, including 100 GW of solar energy, 60 GW of wind energy, 10 GW of biomass energy, and 5 GW of small-scale hydropower. Achieving these targets would mean that solar and wind energy would account for around 20% of India’s total electricity generation by 2022.⁹⁹

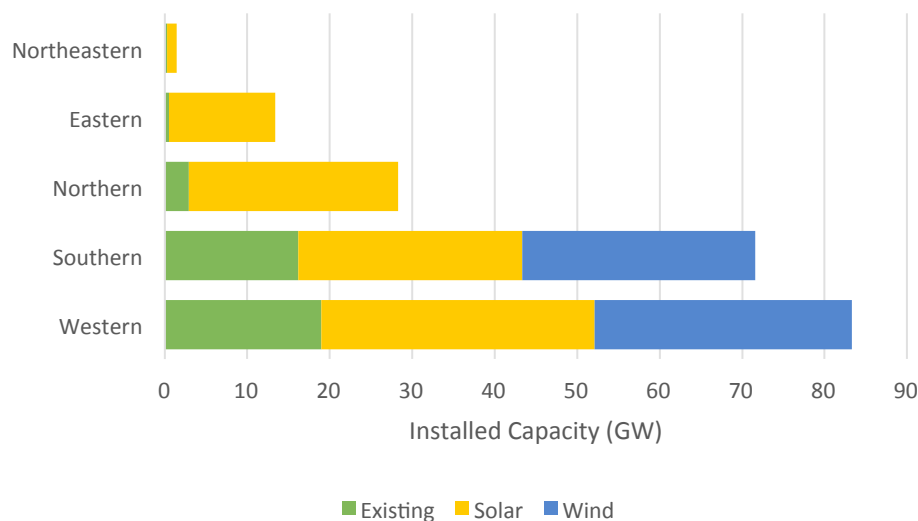
The development of renewable resources thus far, and the anticipated development of wind and solar resources to meet the 2022 goal, are concentrated within states and grid regions. Five states — Tamil Nadu, Maharashtra, Gujarat, Andhra Pradesh, and Rajasthan — accounted for 71% of existing (as of February 2016) renewable generation capacity and are expected to account for 45% of new solar capacity and 76% of new wind capacity by 2022.¹⁰⁰ On a regional grid level, the Western and Southern Grid account for more than 90% of existing (February 2016) renewable generation capacity and more than 75% of anticipated solar and wind capacity additions by 2022 (Figure 22). This concentration of solar and wind resources implies that, for renewable energy to become a larger part of India’s national power mix, delivering power across states and regions will become increasingly important.

⁹⁸ Generation mix data are from Gol, MoP, and CEA (2015). Renewable generation mix data are from Garud (undated).

⁹⁹ This high-level estimate assumes electricity generation growth of 5% to 7% per year between 2015 and 2022, and capacity factors of 20% for solar energy and 30% for wind energy, respectively.

¹⁰⁰ Existing renewable capacity data are from MoP and CEA (2016). Expected solar and wind data are from MNRE, “Tentative State-wise break-up of Renewable Power target to be achieved by the year 2022 So that cumulative achievement is 1,75,000 MW,” <http://mnre.gov.in/file-manager/UserFiles/Tentative-State-wise-break-up-of-Renewable-Power-by-2022.pdf>.

Figure 22. Existing (January 2016) Renewable Generation Capacity and New Solar and Wind Generation Capacity Anticipated by 2022 for India’s Five Grid Regions¹⁰¹



6.3 Interstate Regulations for Forecasting, Scheduling, and Balancing of Renewable Energy

6.3.1 Framework for Renewable Generation

CERC developed an initial framework for renewable energy forecasting, scheduling, and balancing in the Renewable Regulatory Fund (RRF), within the 2010 Indian Electricity Grid Code (IEGC).¹⁰² The RRF sought to strike a balance between incentivizing solar and wind generators to accurately forecast their output, and limiting the commercial impacts of imbalance — or in this case forecast error — charges on these generators to a reasonable range.

Under the RRF mechanism, solar and wind generators meeting four criteria — commissioned after May 2010, above a certain installed capacity threshold, injecting power onto the high voltage transmission system, and delivering power across states — were required to provide a forecast of their generation for 15-minute time intervals during the next day to RLDCs.¹⁰³ Generators were allowed to revise these schedules up to eight times in each three-hour time block beginning from the start of the day.

The RRF limited the scope of charges or payments for deviation from forecasted schedules to wind generators. At the time, wind forecasts were deemed to be more accurate than solar forecasts. CERC proposed that day-ahead wind forecasts should be at least 70% accurate, with imbalance charges assessed to wind generators for deviations up to 30% of their forecasted day-ahead schedule. For solar

¹⁰¹ Ibid.

¹⁰² CERC (2010a).

¹⁰³ Wind generation could be forecasted on an individual developer basis or on an aggregated basis (if above 10 MW and connected at 33kV and above). If resources are not connected through a single substation at the 33kV level, but rather through a common feeder, they can be aggregated at the substation at which the feeder terminates on the distribution system or transmission system level.

and wind forecast errors less than 30%, states purchasing the renewable energy would bear the imbalance charge, with costs later socialized across all states.¹⁰⁴

The RRFs imbalances charges were based on the unscheduled interchange (UI) mechanism, which had been in place for thermal generators since the early 2000s. As described in greater detail in the next section, the UI mechanism is a system of imbalance payments and fees based on a combination of system frequency and an individual generator's deviation from schedule. Generators that were charged under the UI paid fees into a fund, operated by the RLDCs, and the RLDC paid generators eligible for payments under the UI from the fund.

Implementation of the RRF mechanism was postponed three times before it was implemented in July 2013. The RRF met with significant resistance from stakeholders. A significant amount of renewable generation capacity had already been built by May 2010, and these generators were exempted from forecasting requirements and UI charges. States protested that they could not make effective use of partial solar and wind forecasts. States and generators also suggested that the RFF imbalance charges placed too much financial risk on states and generators. Other stakeholders protested against a lack of clarity in the scope of which generators should be included under the RRF. In February 2014, CERC suspended the RRF, pending an overall review.¹⁰⁵

To address stakeholder concerns, in March 2015 CERC released and invited comments on proposed revisions to the RRF,¹⁰⁶ which were finalized in the August 2015 *Framework on Forecasting, Scheduling and Imbalance Handling for Variable Renewable Energy Sources ("Framework")*.¹⁰⁷ The *Framework* revised the forecasting procedures for interstate wind and solar generators and the approach to calculating and settling imbalance charges.

The *Framework* delineates two kinds of forecasts: 1) forecasts by RLDCs to ensure efficient and secure dispatch across the region; and 2) forecasts by generators at the wind or solar plant level to inform plant schedules. The former forecasts are to be supported by Renewable Energy Management Centers (REMCs), which were established to provide advanced forecasting capabilities to the RLDCs.¹⁰⁸ Wind and solar generators will have the option of using the forecasts provided by the RLDCs/REMCs, but will be responsible for the commercial impacts of whichever forecast they choose to use. To enable higher forecast accuracy, the *Framework* expanded the number of allowed schedule revisions to 16 (from 8) and reduced the size of the scheduling window to one-and-a-half-hour time blocks (from three-hour time blocks).

¹⁰⁴ Cost allocation across states was to be based on a load ratio share basis, based on monthly peak demands. For solar forecast errors greater than 30% imbalance charges would be borne by all states based on a preset formula.

¹⁰⁵ For an overview of stakeholder concerns, see REConnect, "Wind & Solar Forecasting & Scheduling Regulations 2015," <http://reconnectenergy.com/blog/2015/08/wind-solar-forecasting-scheduling-regulations-2015/>.

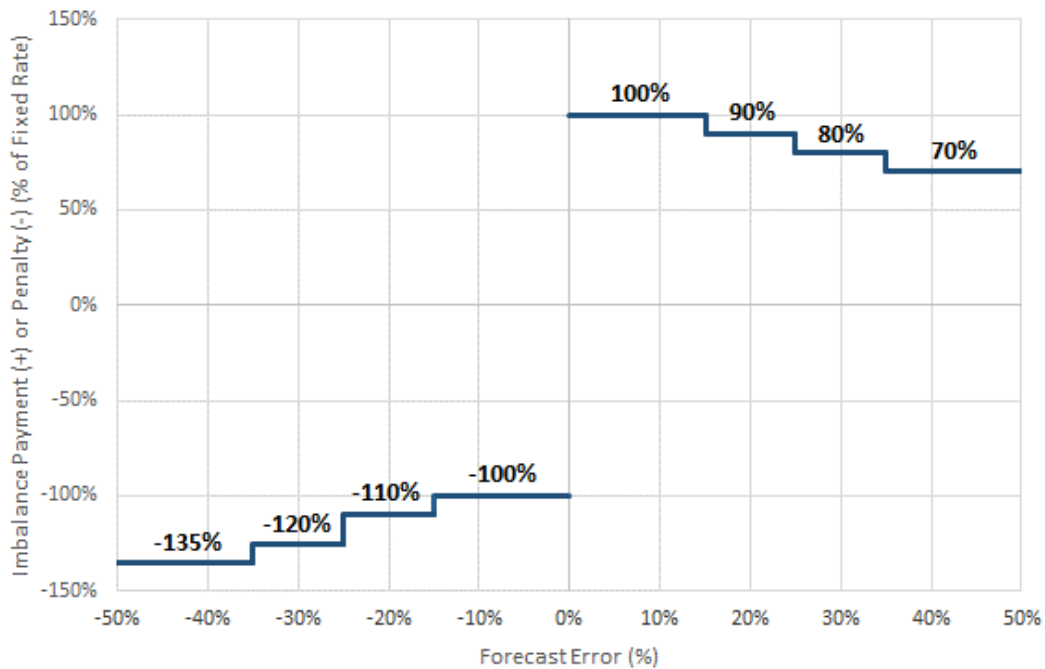
¹⁰⁶ CERC (2015a).

¹⁰⁷ CERC (2015a).

¹⁰⁸ REMCs were initially proposed in CEA (2013).

CERC also revised the RRF mechanism’s approach to imbalance charges. Rather than tying imbalance charges to system frequency, the *Framework* established a separate tiered system of imbalance payments and penalties tied to renewable generators’ power purchase agreements (PPAs) (Figure 23). These charges are assessed on the basis of average forecast error in each 15-minute interval, normalized by available capacity,¹⁰⁹ and are payable to and from a centralized fund (“pool”) maintained by RLDCs. Under the *Framework*, solar and wind generators are paid on the basis of scheduled, rather than actual generation, which effectively means that on net they are paid their PPA price for actual generation within 15% of their forecasted schedule.

Figure 23. Tiered Imbalance Charges (Payments and Penalties) for Wind and Solar Generators under the Framework on Forecasting, Scheduling and Imbalance Handling for Variable Renewable Energy Sources



As an example, consider a 50 MW wind generator with a 4.0 Rs/kWh PPA. In some hypothetical hour (four 15-minute blocks), suppose that this generator has a 40 MW forecast (hourly average) and actually delivers an average of 35 MW. It thus has an average forecast error of 5 MW (= 40 MW – 35 MW), an average normalized forecast error of 10% (= [40 – 35]/50), and is within the 15% deviation band. The generator will be paid 160,000 Rs in that hour (= 40 MW × 4.0 Rs/kWh) as per schedule, and will pay a total of 20,000 Rs to the pool (= 4.0 Rs/kWh × [5.0 MW × 100%]) in imbalance charges. This leads to a net of 140,000 Rs for 35 MW generated in that hour, which is equivalent to the PPA price of 4.0 Rs/kWh (= 140,000 Rs / 35 MW).

¹⁰⁹ That is, forecast error (ϵ) is defined as $\epsilon = \frac{F-A}{AvC}$, where F is the forecasted value, A is the actual value, and AvC is the available capacity of the individual or aggregated plant unit. Available capacity is installed capacity adjusted for unforced outages.

Now suppose that this generator has a 40 MW forecast and only delivers an average of 30 MW. It thus has an average forecast error of 10 MW (= 40 MW – 30 MW) and an average normalized forecast error of 20% (= [40 – 30]/50). The generator will still be paid 160,000 Rs, but will pay a total of 41,000 Rs in imbalance charges (= 4.0 Rs/kWh × [7.5 MW × 100% + 2.5 MW × 110%]) to the pool. In this case, the generator will net 119,000 Rs for 30 MW generated, or an average price of 3.97 Rs/kWh and a net deviation charge of 0.03 Rs/kWh.

Under the *Framework*, RECs are allocated to generators based on scheduled rather than actual generation. CERC had originally proposed that individual solar and wind generators would be required to procure RECs to make up any shortfalls between scheduled and forecasted generation. However, the *Framework* ultimately centralized responsibility for managing the REC implications of differences between scheduled and actual generation through the NLDC. If there is less renewable generation than scheduled in a month, the NLDC will purchase RECs from the market to make up for the difference using funds from the pool of imbalance charges. If there is more renewable generation than scheduled in a month, RECs will be credited to the imbalance pool and carried forward to the next month.

6.3.2 Framework for Non-Renewable Resources

Interstate non-renewable generation consists of three main forms: (1) central government-owned generators that have their capacity allocated to multiple states, (2) shorter-term bilateral contracts between state discoms, and (3) power transactions through the power exchanges.

Since the early 2000s, central government-owned generation has been subject to a two-part tariff — an availability-based tariff (ABT) — that compensates generators separately for capacity and energy. Capacity payments are made on the basis of the available capacity declared by the plant on a day-ahead basis. Energy payments are based on scheduled generation. States own shares of capacity, and have rights to schedule generation up to their allocated capacity. In principle, the ABT enables more efficient use of interstate generators by off-taker states, by enabling SLDCs to schedule these generators in merit order.

The ABT also included an unscheduled interchange (UI) mechanism, as a short-term balancing mechanism.¹¹⁰ The UI mechanism sought to address frequency “excursions” in the regional grids. To maintain a given system frequency — in India 50 Hertz (Hz) — system operators must keep loads and generation in constant balance. If load exceeds generation, system frequency will fall below 50 Hz; if generation exceeds load, it will rise above 50 Hz. In on-peak (high load) periods, system frequency was often below 50 Hz, whereas in off-peak (low load) periods, it was often below 50 Hz.

The UI mechanism provided decentralized incentives for load serving entities and generators to correct frequency excursions, by creating a system of imbalance charges (payments and penalties) tied to system frequency and schedule deviations:

¹¹⁰ See CERC (2010b).

- **Low system frequency (load > generation)** — load serving entities were penalized for consuming more than their scheduled amount of interstate generation (“over-withdrawal”) and paid for consuming less than this amount (“under-withdrawal”); generators were penalized for generating more less than their schedule (“under-injection”) and paid for generating more than their schedule (“over-injection”) (Table 9).
- **High system frequency (generation > load)** — load serving entities and generation were given a small to zero penalty for under-withdrawal and over-injection, respectively, and a small to zero payment for over-withdrawal and under-injection.

Table 9. UI Charges on Loads and Generators

System Frequency	Loads	Generation	UI Charge
Low	Over-withdrawal	Under-injection	Penalty
	Under-withdrawal	Over-injection	Payment
High	Over-withdrawal	Under-injection	Zero to small payment
	Under-withdrawal	Over-injection	Zero to small penalty

The UI charged was composed of two parts: (1) an upward sloped charge tied to system frequency, and (2) a tiered charge linked to an individual load serving entity’s or generator’s deviation from schedule. The former provided marginal incentives for the system, while the latter effectively acted as an imbalance charge on interstate interchange schedules.

The RLDCs and RPCs managed the scheduling and balancing process associated with the UI in five steps:

- 1) Interstate generators declared their availability for each 15-minute time block the following day.
- 2) Based on available capacity and contracts, RLDCs communicated to each state how much interstate generation capacity they had.
- 3) SLDCs submitted their power demands for these generators for the next day to the RLDCs.
- 4) The RLDCs prepared interstate generation schedules, accounting for generator and transmission constraints.
- 5) The RPCs settle accounts for load serving entities and generators on a periodic basis; imbalance charges are paid to and from a pool.

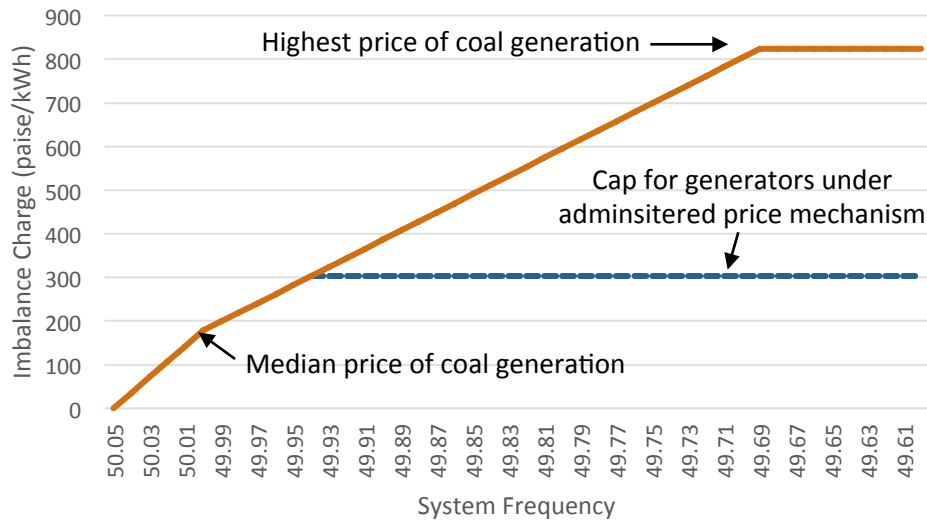
In 2014, responding to large-scale power outages in 2012, CERC replaced the UI mechanism with a deviation settlement mechanism (DSM).¹¹¹ The DSM changed methodological details associated with the UI, but left its architecture largely intact.

With the DSM, load serving entities and generators pay a two-part imbalance charge, as under the UI. The price schedule for the frequency-based imbalance charge, shown in Figure 24, is based on three price points. The first point, at 50.05 Hz, is zero, meaning that above 50.05 Hz there are no imbalance

¹¹¹ CERC (2014).

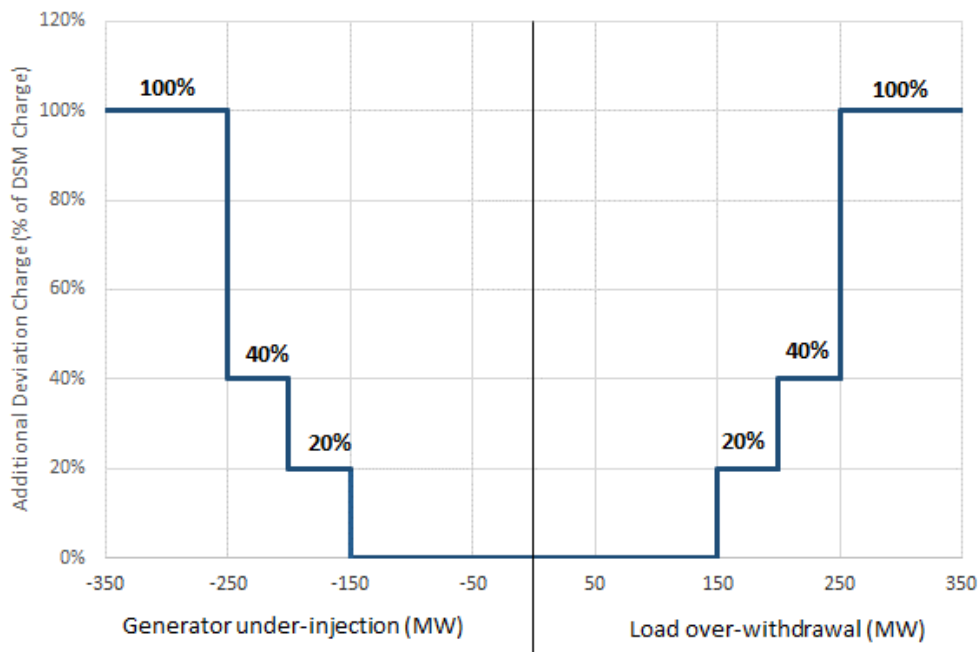
payments or penalties. The second point, at 50.01 Hz (178 paise/kWh in Figure 24), is based on the median value of average energy costs for coal-fired generators regulated by CERC over a six-month period. The third point, at 49.70 Hz (824.04 paise/kWh in Figure 24), is based on the highest value of average energy costs for coal-fired generators regulated by CERC over a six-month period. For interstate generators purchasing fuel under the administered price mechanism (APM), imbalance charges are capped at the energy cost of imported coal (303.04 paise/kWh in Figure 24).

Figure 24. Frequency-Based Imbalance Charge Schedule under the DSM



The second part of the DSM imbalance charge — referred to as the additional deviation charge — is based on over-withdrawals (loads) or under-injections (generators) that exceed 150 MW or 12% of schedule, whichever is lower. For deviations between 150 MW and up to 200 MW or 12% and up to 15% of schedule, loads and generators pay 20% of the frequency-based imbalance charge. For deviations between 200 and up to 250 MW or 15% to up to 20% of schedule, loads and generators pay 40% of the charge. For deviations in excess of these, penalties are assessed at 100% of the deviation charge.

Figure 25. Additional Deviation Charge for Over-Withdrawal (Loads) and Under-Injection (Generators), When Deviations Exceed 150 MW



Consider, for instance, a 300 MW interstate generator paying that pays APM fuel prices. In a given hour, this generator is scheduled for an average of 300 MW but actually generates 275 MW when average system frequency is 49.80 Hz. In this case, the frequency-based DSM charge is 75,760 Rs (= 303.04 paise/kWh × 25 MW) and there is no additional deviation charge because the deviation (25 MW, 8%) is less than 150 MW or 12%. If actual generation was 250 MW, the generator would have paid a frequency-based penalty of 151,520 Rs (= 303.04 paise/kWh × 25 MW) and an additional deviation charge of 3,030 Rs (= 5 MW × 20% × 303.04 paise/kWh), or a total charge of 154,550 Rs.

Although interstate renewable generation is treated separately under the DSM, intrastate renewable generation may have implications for DSM charges on state discoms. States with significant intrastate wind and solar generation adjust their demands for interstate generation on the basis of real-time changes in demand and wind and solar output, which can lead to large deviations from day-ahead schedules. For instance, consider a discom with 500 MW of day-ahead scheduled interstate generation. If intrastate wind generation is 200 MW lower than anticipated and demand is 50 MW higher than expected, the state’s DSM deviation from day-ahead schedule would be 250 MW (25%). Before 2015, the state would have been subjected to both frequency-based charges and additional deviation charges under the DSM.

Additional deviation charge thresholds (“DSM limits”) — the maximum over-withdrawal before penalties are imposed — act as an effective intraday import constraint on states. In 2015, CERC proposed setting DSM limits for states (loads) based on a percentage of peak demand in the previous

year.¹¹² CERC ultimately rejected this approach, but loosened DSM limits on renewable rich states.¹¹³ States with 1,000 MW to 3,000 MW of solar and wind capacity are now allowed 200 MW deviation limits; states with greater than 3,000 MW of solar and wind capacity are now allowed 250 MW deviation limits.

Before 2016, the DSM functioned as a decentralized imbalance mechanism on all timescales. In 2015, CERC passed an *Ancillary Services Operations Regulation*, which provided a framework for allowing the RLDCs to centrally dispatch interstate generating units to maintain grid frequency, and to compensate generators providing this service.¹¹⁴ To determine which generators should provide ancillary services, RLDCs create a regional merit order stack of unscheduled interstate generation capacity, based on reported variable costs and accounting for transmission constraints. RLDCs can then dispatch this capacity in response to seven events:

- “Extreme weather forecasts and/or special day;
- Multiple generating unit or transmission line outages;
- Trend of load met;
- Trends of frequency;
- Intimation of any abnormal event such as outage of hydro generating;
- Units due to silt, coal supply blockade etc.;
- Excessive loop flows leading to congestion; and
- Such other events.”¹¹⁵

RPCs are charged with settling ancillary service payments, on the basis of reported fixed and variable costs.

6.4 State Model Regulations

The Forum of Regulators (FOR), a body of regulators from the central and state electricity regulatory commissions, convene to analyze tariff orders and harmonize regulations between the central and state levels, among other responsibilities, several times a year. Through the analysis and harmonization process, the FOR occasionally provides model regulations that State Electricity Regulatory Commissions (SERCs) can use as a template from which to base its own regulations. States are not required to use the model regulations and can issue separate regulations entirely if they choose.

Following on CERC’s *Framework*, the Forum of Indian Regulators (FOR) issued *Model Regulations on Forecasting, Scheduling and Deviation Settlement of Wind and Solar Generating Stations at the State Level* (“FOR Model Regulations”) in 2015.¹¹⁶ The FOR’s *Model Regulations* closely mirror CERC’s *Framework*, with some key differences.

¹¹² CERC (2015d).

¹¹³ CERC (2016).

¹¹⁴ CERC (2015c).

¹¹⁵ CERC (2015c), p. 3.

¹¹⁶ FOR (2015).

Under the FOR's *Model Regulations*, wind and solar generators are required to provide their own forecasts or use the State Load Dispatch Center's (SLDC's) forecast on a day-ahead basis in 15-minute time increments and bear the commercial impacts of whichever forecast they choose to use. Schedule revisions are allowed up to 16 times a day, consistent with the *Framework*. The *Model Regulations* differ from the *Framework* in four key areas: 1) provision of a week-ahead forecast in addition to the day-ahead forecast; 2) payment settlement based on actual generation, rather than scheduled generation, for intrastate sales; 3) the introduction of qualified coordinating agencies (QCAs); and 4) tightening of the deviation bands from 15% (in the *Framework*) to 10% for new generators.

A key difference between the *Model Regulations* and the *Framework* is the introduction of the QCA concept and its related tightening of the deviation tolerance bands. The QCA is defined as a state entity that can forecast for an aggregated set of wind and solar facilities that are measured at a single substation, and is responsible for metering, collecting data, and communicating with the distribution companies (discoms), SLDCs, and other relevant agencies. QCAs can be an individual generator within the aggregate pool or another agency entirely. The QCA is also responsible for commercial settlements of the state DSM pool and allocates payments to individual generators within its aggregation. When charges are made or payments are given to aggregated facilities, QCAs are responsible for allocating the deviation charges to the individual generators either on the basis of the actual generation share or share of available capacity.

With the introduction of the aggregator framework, the FOR reduced the deviation tolerance band from 15% down to 10% for new projects. FOR felt that with QCAs, accuracy within 10% should be achievable based on internal simulation results. Existing projects, however, fall under the 15% threshold.