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BERKELEY NATIONAL LABORATORY

Power Consumption, Demand and Competition Cooperation: Recommendations for the Pilots in Guangdong, Jilin, Jiangsu, and Shanghai

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December 2017

This work was supported by the U.S. Department of State, Bureau of Energy Resources under contract #DE-AC02-05CH11231 with the Regents of the University of California

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Acknowledgements

The authors thank Bureau of Energy Resources of the U.S. Department of State for funding under contract #DE-AC02-05CH11231 with the Regents of the University of California.

Acronyms and Abbreviations

A/S	Ancillary services
AutoDR	Automated demand response
BA	Balancing area
DR	Demand Response
CfD	Contract for differences
CHP	Combined heat and power
ComEd	Commonwealth Edison (Chicago)
ConEdison	Consolidated Edison (New York City)
CPP	Critical peaking price
CPUC	California Public Utilities Commission
DER	Distributed energy resource
DOE	U.S. Department of Energy
DRAM	California Demand Response Auction Mechanism
DSM	Demand-side management
EE	Energy efficiency
EERS	Energy Efficiency Resource Standard
EIM	Energy imbalance market
EV	Electric vehicles
FERC	U.S. Federal Energy Regulatory Commission
FIT	Feed-in tariff
FYP	Five-Year Plan (China)
GHG	Greenhouse Gas
ISO	Independent System Operator
M&V	Measurement and Verification
NDRC	National Development & Reform Commission (China)
NEA	National Energy Administration (China)
NERC	North American Electric Reliability Corporation
PG&E	Pacific Gas & Electric
PJM	PJM Interconnection
PPA	Power purchase agreement
PV	Photovoltaics
RE	Renewable energy
REC	Renewable energy certificate or renewable energy credit
REV	Reforming the Energy Vision
RPS	Renewable portfolio standard
RTO	Regional Transmission Organization
RTP	Real-time pricing
SBC	Systems benefit charge
SPP	Southwest Power Pool
SREC	Solar renewable energy credit
T&D	Transmission & distribution
TOU	Time-of-use
TSO	Transmission system operator
USofA	Uniform System of Account
V2G	vehicle to grid
WECC	Western Electricity Coordinating Council

Executive Summary

Under the U.S.-China Power Consumption, Demand and Competition Cooperation (the "Cooperation"), the United States and China are collaborating on institutional frameworks and policies to foster a competitive, transparent and sustainable electric power system in China. Both countries are cooperating to identify solutions to advance key elements of China's comprehensive power sector reforms through pilot projects on three topics:

1. **Promoting electric power market competition and direct power trading in Guangdong:** To help formulate market rules, policies, and oversight mechanisms supporting overall power sector improvement, while promoting incorporation of clean energy resources in the market.

2. **Increasing the local consumption and reducing curtailment of renewable energy in Jilin:** To reduce provincial wind curtailment through measures focused on making the province's electricity and heating sectors more flexible to accommodate wind generation.

3. **Enhancing demand response (DR) and promoting demand-side resources in Jiangsu and Shanghai:** To develop an enabling policy framework and market mechanisms that encourage and expand DR participation for industrial, commercial, and residential customers and to design electricity markets that can elicit value from DR.

Launched in 2016, the Cooperation has held study tours to both countries and discussed preliminary recommendations. It culminates in joint development of this report on policy recommendations to improve the pilots and guide replication across provinces.

The policy recommendations for China's pilots support the premise that a more open and competitive electric power market could enable participation of diverse players and energy resources in China's power system; make its grid more reliable, flexible, and efficient, lowering total long-run costs; and improve air quality and reduce greenhouse gas (GHG) emissions.

Care should be taken to reconcile the objectives of China's broader economic and environmental reforms with its electricity sector reforms to better assure they not operate at cross purposes and to provide the best chance of success in realizing the physical and economic efficiency gains of competition in the electricity sector.

The attached summary highlights key near- and long-term recommendations by pilot. Looking across the recommendations, four common themes emerge:

1. **Institutionalizing economic dispatch and creating spot markets to promote efficiency and competition:** Spot markets can help achieve the goals of China's electric power sector restructuring, by using market forces to improve economic efficiency. A well-designed spot market will minimize total operating costs by enabling economic dispatch, where resources are dispatched according to their marginal cost. U.S. experience illustrates that spot market design is complex and challenging. In view of the challenges, including the difficulties of ensuring adequate competition, a measured approach to spot market design is warranted. This measured approach could include economic dispatch based on regularly updated costs reported by generators, with well-publicized, consistently applied methods and a single market clearing price, as a transitional step towards competition. This approach could also set the foundation for

day-ahead and intra-day bidding, helping habituate Chinese regulators, system operators, and market players to economic dispatch, market operations and rules, and participation in markets more generally.

Market monitoring and market power mitigation protections should be addressed at the market design stage and not as an afterthought. An important step in designing effective market monitoring and mitigation is a deeper understanding of generator costs and establishment of a register and reporting mechanism for those costs, in which the methodology is consistent across companies. Enlarging the market footprint to create a regional market can increase operational efficiency and power system flexibility and can build on existing institutions (e.g., regional grid companies) and mechanisms (e.g., the Northeast ancillary service market). Finally, limiting the size of transition payments to retiring surplus generation units over a well-defined period can avoid prolonged operation of inefficient generators and increase cost savings for consumers.

2. **Enhancing DR to increase efficiency and flexibility**: As a cost-effective alternative to generation, transmission, and distribution resources, DR has significant potential to improve reliability and flexibility in China's power systems while lowering the cost of electricity, by: reducing peak demand, providing reserve capacity, reducing renewable energy curtailment, and improving market efficiency. DR's inability to scale in China so far can be traced to three primary factors: 1) the lack of funding and incentive mechanisms for encouraging and sustaining DR participation, 2) the lack of market mechanisms to monetize and scale DR, and 3) the lack of viable business models for DR service providers. In the United States, strategies for encouraging and sustaining DR participation include: stable, cost-effective, ratepayer-funded mechanisms to recover DR-related costs; compensation schemes for DR services bundled with necessary penalties; and time-varying tariffs to trigger demand-load modification. These strategies could help China scale DR. Moreover, U.S. experience offers a progression by which DR could be monetized and scaled in China, perhaps beginning with grid company procurement of DR from DR service providers through bilateral agreements or auctions, later augmented by DR participation in electricity markets. Finally, with viable business models, DR aggregators could expand the scope of their services, such as taking the responsibilities for the administration and acquisition of DR resources and providing integrated "benefits stacking" services to meet the needs of distribution companies and grid operators.

3. **Integrating renewable energy into electricity markets to lower costs:** In the context of dramatic drops in installed costs for wind and solar generation, policy changes and the integration of renewable generation into electricity markets can transition to a more competitive framework, with lower prices, more efficient use of renewable generation, and diverse market participants. This transition could be achieved by strengthening the implementation of existing renewable energy policy and introducing competitive procurement and contracts. Well-designed spot markets can help ensure that renewable generation is efficiently integrated and operated.

4. **Supporting retail pricing reforms and markets to align with policy goals:** Effective retail pricing can align customer behavior with provincial and national objectives for China's power sector. In the near term, new designs for regulated retail tariffs, such as seasonal time-of-use pricing, can enhance demand-side flexibility and align electricity consumption with periods of low system costs. In the longer term, more dynamic or even real-time tariffs could enable

more responsive demand, because they better reflect real-time power system conditions. For competitive retail markets, timely and accurate standardized information disclosure and effective retail regulation will help consumers make rational electricity use decisions.

Summary of Recommendations

I. <u>Promoting Electric Power Market Competition and Direct Power Trading</u>

The Guangdong pilot seeks to formulate market rules, policies and oversight mechanisms, while promoting the incorporation of clean energy resources, such as renewables and demand-side resources, in the restructured market system. This paper offers recommendations for this pilot in three specific topic areas based on U.S. experience: 1) wholesale "spot market" development, 2) retail market development, and 3) measures to facilitate greater participation of renewable energy resources in the market.

1. **<u>Wholesale "Spot Market" Development</u>:** For purposes of this paper, the term 'spot market' refers to a package of market mechanisms, centered on a 'real-time' market which features clearing prices for each intra-day time period (which in the United States are set based on time intervals of fifteen minutes or less). This package also includes a day-ahead market in which supply and demand is scheduled to meet expected demand the following day on a least-cost basis, as well as mechanisms to rationally compensate provision of ancillary services.

- ***Establish spot markets with merit order dispatch based initially on reported operating cost basis (Recommendation 1)***

  - Market design is the process of determining the optimal combination of explicit regulation and market mechanisms to minimize economic inefficiencies. A well-designed spot market will minimize operating costs by enabling a merit order approach to dispatching power according to resources' marginal cost.

  - Two possible approaches to establishing merit order dispatch in a spot market include: 1) a structure for bidding in generator reported costs, and 2) a structure based on short-run bids by generators and other resources. A single market clearing price can be used with both approaches. With a single market clearing price, all suppliers receive, and all loads pay, the market clearing price.

    - In a generator reported cost bid structure, the system operator uses estimates of the short-run variable operating cost of each generation unit to construct a merit order and set the market-clearing price, which is typically equal to the operating cost of the highest cost generation unit necessary to meet demand. These cost estimates are subject to confirmation or audit.

    - A generator short-run bid structure uses bids to buy and offers to sell electricity, resulting in competition that induces each generator to reveal its operating cost to construct a merit order and set the market-clearing price, which is equal to the highest cost generation unit necessary to meet demand.

    - The choice between a generator reported cost bid structure versus a generator short-run bid structure will hinge on relative confidence in each approach's ability, among other things, to reveal accurate operating costs, maintain the independence of the market and system operator, and enforce a rigorous system of market monitoring and market power mitigation.

- Spot market design is complex and challenging, given the difficulties of ensuring adequate competition. A measured approach is warranted, such as follows.

- In the near term, implement a generator reported cost-bid structure because it would sidestep the need for robust competition, which U.S. experience with spot markets indicates can be difficult to ensure. It would set up the foundational elements relating to operating cost reporting, pricing for inputs and at output locations, and market monitoring and market power mitigation needed for both approaches. As such, it serves as an initial, transitional step before moving to a generator short-run bid structure in the long term.

- Assessment of operating costs in an administrative process under a generator reported cost-bid structure, with well-publicized and consistently applied methods, will help habituate regulators, system operators, and market players to the merit order dispatch approach. This will increase the likelihood of success of a later adopted generator short-run bid structure.

- ***Establish an institutional framework protective against interference with merit order dispatch (Recommendation 2)***

  - In the United States, the legal and regulatory frameworks to ensure that dispatch decisions are focused on efficient and least-cost outcomes have evolved around three broad models: 1) independent system operator that does not own generation or transmission assets, 2) system operator within a vertically integrated company that owns generation and transmission assets, and 3) system operator within a grid company that does not own generation assets but owns transmission assets.

  - Whichever model is chosen, the key to ensuring economic dispatch is through market rules that require: 1) rules and transparency around dispatch decisions, and 2) operation of the transmission system in an "open" and accessible manner for any generator that wants to use it, enabling long-term competition of resources and rationally disciplined resource entry and exit decisions.

  - In the near term, new regulations could be established to foster efficient operations and support competition by requiring publication of market and dispatch procedures and of detailed information about system conditions on a monthly, daily, hourly, and forecast basis (e.g., clearing prices, congestion re-dispatch, load and wind/solar forecasts, transmission outages, and ancillary services requirements). Publication of market data and system conditions can be aggregated to protect confidential information.

    - Transparency in market and dispatch procedures and system conditions allows market participants to develop an accurate view of conditions and develop effective strategies. Such transparency also supports effective regulation.

- ***Establish a transitional strategy to market prices by limiting transition payments to retiring generation capacity and facilitating measured retirement of excess generation capacity (Recommendation 3)***

  - Given a context of substantial excess generation capacity, a well-designed wholesale market will send signals to close down generation capacity, particularly generators with higher operating cost (i.e., relatively inefficient generators). The challenge is to ensure market signals lead to smooth retirement of unneeded capacity.

  - Some near- and long-term recommendations for a transition strategy are as follows:

    - Limit out-of-market payments to reduce incentives for ongoing overbuilding of capacity and avoid unnecessary interference with market signals in support of repeated Chinese government warnings to generation companies against investment in excess capacity.

    - Limit the size of transition payments that are offered to existing, retiring excess units to a short, well-defined transition period, in order to avoid prolonged operation of inefficient capacity and to incentivize market exit of inefficient generators when appropriate.

    - Use long-term regional planning and resource adequacy assessments as the reasoned basis for determining which resources are necessary for reliability in order to make both temporary measures for these resources and market design adjustments.

- ***Develop a rigorous framework for market monitoring, market power mitigation and enforcement (Recommendation 4)***

  - To build effective protections, it is important for China's central government to address market monitoring and market power mitigation at an early stage, when provinces are working on market design, rather than as an afterthought.

  - An important step in designing effective market monitoring and mitigation is a deeper understanding of generator costs and establishment of a register and reporting mechanism for those costs in which the methodology is consistent across companies.

  - The near-term generator reported cost-bid structure can serve as the foundation for a market monitoring, market power mitigation and enforcement structure that will support the longer-term implementation of a generator short-run bid structure. The information collected under the generator reported cost-bid structure to estimate operating cost should be pursuant to books and records maintained in accord with a consistent set of accounting rules (e.g., FERC's Uniform System of Accounts).

  - This information would similarly be collected to support monitoring and enforcement under a generator short-run bid structure. For instance, if Guangdong decides to implement a generator reported cost-bid structure in the near term, we recommend creating a database of reference costs by generator to enable surveys and verification of cost data. This will better ensure that the cost- reporting mechanisms can evolve into a robust market monitoring and enforcement structure for a generator short-run bid structure.

- If Guangdong chooses to implement a generator short-run bid structure for its spot market in the near-term, it should not be implemented until a robust and effective market monitoring enforcement structure is in place, given the susceptibility of short-run bid structures to market power, because electricity supply and demand must be matched on a second-by-second basis. Otherwise, generators with market power can engage in behavior detrimental to consumers and to efficient system operation (e.g., withholding capacity) because they are not properly incentivized to reveal accurate operating and opportunity costs.

- For eventual implementation of a generator short-run bid structure, we recommend establishing tests for market power and codifying mitigation responses. These tests should include: 1) the potential of a generator to exercise market power based on analysis of competitiveness and grid constraints, 2) the degree of a generator's ownership concentration in a market, and 3) the extent a generator has actually submitted bids in excess of its own true operating costs by a significant margin. Additional requirements should include: 1) imposing mitigation and penalties in a transparent fashion, and 2) establishing independent market monitors to promote transparency by reporting on overall market functioning.

- ***Enlarge market footprint to create a regional market with integrated multi-province economic dispatch (Recommendation 5)***

  - If well-designed, larger market footprints will increase operational efficiency and power system flexibility by significantly reducing the variability of renewables through access to greater diversity of generation and loads and larger pools of reserves.

  - We recommend moving toward ***fully integrated multi-provincial economic dispatch***. This can take the form of reserve sharing between provincial balancing areas (BAs) before progressing to coordinated scheduling, coordinated operations of an energy imbalance market (EIM), and eventually a fully integrated market.

    - ***Reserve sharing*** involves two or more BAs collectively maintaining, allocating, and supplying the reserves required for each BA.

    - ***Coordinated scheduling*** involves establishment of 1) an information exchange system for generator availability and cost, 2) a monitoring system and financial compensation mechanisms for energy exchanges and transmission usage, and 3) transmission availability calculation on a day-ahead or short-term dispatch basis.

    - In an ***EIM***, an individual BA or market operator is responsible for implementing a real-time security constrained dispatch of energy to modulate or reduce imbalances of load and generation across multiple BAs, while individual BAs retain residual reliability functions (e.g., regulation services).

- Pricing and contractual reforms will also need to be considered to address the financial impacts on generators from such a change in dispatch procedures.

▪ In the long term, we recommend ***creation of a fully integrated regional spot market in the Southern Grid footprint***.

- ***Design ancillary services based on system reliability and stability requirements (Recommendation 6)***

  ▪ Pricing for energy and ancillary services (A/S) should be unbundled to minimize averaging of costs (e.g., for congestion, reserves, or other costs), as averaging fails to send correct price signals for the supply of specific services. Otherwise, the system operator has no ability to shop for the lowest cost A/S products to meet performance requirements, resulting in higher overall system operation cost and risk for reliability violations.

  ▪ A/S markets should be resource neutral and be compensated for performance, enabling all supply- and demand-side resources to compete on a level playing field as long as they can provide reliability services under required parameters.

  ▪ In the near term, we recommend initiation of a process based on system reliability studies to identify needed ancillary services which should be administratively priced on an unbundled basis based on cost.

  ▪ In the mid- to long-term, we recommend that A/S mechanisms for each service be established and that all supply- and demand-side resources be allowed to compete in an A/S market based on the resource's reliability contributions.

2. <u>Retail Market Development</u>: U.S. best practice suggests that China's retail market should be designed according to principles of fairness, economic efficiency and sustainability.

- ***Encourage "smart" pricing in the new competitive retail market (Recommendation 7)***

  ▪ Customers should be influenced to behave in ways that help meet provincial and national objectives for China's electric power sector and environment. Our recommendations build upon Guangdong's existing "smart" pricing policies as follows.

  ▪ In the near term, maintain "differential pricing" by continuing to require large industrial end-users be subject to this pricing based on their energy consumption classification, even as they acquire access to competing retail offerings.

  ▪ In the long term, foster more flexible and dynamic real-time pricing, such as retailer access to real-time spot market prices, minimum performance requirements and technical specifications for advanced metering infrastructure and creating wholesale market mechanisms that value and reward flexibility in demand.

  - Retail competition should be carefully managed with the transition to a well-functioning national carbon emissions pricing scheme. The challenge is to better assure the opposite pricing trends from both these initiatives - downward pressure in the former and upward pressure in the latter – do not work at cross-purposes. Strengthening the differences in the pricing policies could help reconcile these trends.

- ***Promote retail market transparency by developing standardized procedures for information disclosure (Recommendation 8)***

  - Consumers cannot make rational purchasing decisions without access to timely and accurate information about products and services. Some U.S. states have adopted information disclosure rules with which all suppliers must comply. This approach is helpful to bringing transparency and comparability to the range of available retail options in the market.

  - In the near term, consider adopting a standardized format for information disclosure (e.g., on contract terms, pricing, emissions content) for retailers and suppliers.

  - In the longer term, consider implementing a regulatory structure to oversee and test the veracity of retailers' information through random audits of retailers' public declarations as compared to their actual resource portfolios (both owned and purchased). This could be integrated with China's "green certificate" scheme, so that retailers claiming renewable energy content should be required to show acquisition of corresponding renewable energy credits.

3. <u>Facilitating Greater Participation of Renewable Energy Resources in the Market</u>: U.S. policy-driven approaches have supported renewable energy participation in electricity markets.

- ***Design an effective renewable portfolio standard, supported by green certification (Recommendation 9)***

  - China's provincial renewable portfolio standard (RPS) stipulates that green certificates be used as a tracking and auditing mechanism for meeting the renewable energy targets but details on implementation could be better clarified.

  - In the United States, RPS is implemented as a requirement on load-serving entities (including retail electric suppliers), typically backed with some form of penalties for non-performance, and is accompanied by a tradable green certificates (known as RECs; renewable energy credits) program to facilitate compliance.

  - Based on U.S experience with RPS, we recommend a clear point of RPS implementation, namely by placing the procurement obligation on load-serving entities (including retailers and large end-users) and imposing strict penalties for non-compliance to ensure the effectiveness of RPS.

- A central authority with the capacity to handle tracking and certification, as well as a well-developed contractual framework, should be established. As a province with high electricity demand and relatively low utility-scale solar and onshore wind potential, Guangdong has the potential to meet high RPS goals through purchasing out-of-province renewable energy or RECs.

- In the long term, we recommend coordinating the RPS with an improved resource planning process such that the RPS could become more stringent as costs fall and could be key to lowering renewable subsidies.

• ***Enable corporate procurement of renewable energy through options which customers may shop to meet business needs (Recommendation 10)***

  - In the United States, corporate end users have driven a substantial amount of new renewable energy development to hedge against electricity price volatility and demonstrate corporate sustainability commitments.

  - Corporate consumers could be afforded a range of options by which to procure renewable energy in China to enable them to shop for and choose the option that best meets their business needs.

  - These options include distributed generation, the newly launched green certificate mechanism and a utility green tariff with verifiable green energy tracking at a reported cost-based price.

  - We also recommend renewable generators, including out-of-province resources, be encouraged to participate in the medium-to-long-term market to create additional pressure to support interprovincial trade.

  - In the medium-to-long-term, enable corporate customers to enter into power purchase agreements, structured as contract for differences, with renewable generators or third-parties procuring renewable energy.

  - Finally, the development of integrated wholesale markets will enable renewable energy projects to be developed where it is most economic to do so, even across provinces.

II. Increasing the Local Consumption of Renewable Energy

The Jilin pilot seeks to reduce provincial wind curtailment through a series of measures focused on making the province's electricity and heating sectors more flexible to accommodate wind generation. This paper offers recommendations for this pilot in three specific topic areas based on U.S. experience: 1) business models for electric heating and flexible loads, 2) market-based, policy supported approaches to renewable energy development, and 3) heating sector reform and coordination.

1. **<u>Business Models for Electric Heating and Flexible Loads</u>**

- ***Investigate new designs for retail electricity tariffs that create business models for electric heating and other flexible electric loads (Recommendation 1)***

  - Shifting electric loads to better match the timing of wind generation can reduce wind curtailment. Without incentives, customers are unlikely to invest in technologies that enable this greater flexibility and responsiveness in electricity demand. New retail tariff designs can help to provide incentives, by creating business models for new technology manufacturers and retail customers, and encourage more conventional demand response.

  - Jilin currently has traditional on-peak and off-peak pricing for industrial customers and residential electric heating in single family homes. Building on these tariffs, we recommend that Jilin explore expanded access and new designs for retail tariffs, in order to create business models for investments in demand-side flexibility.

  - In the near term, three incremental steps to increase demand-side flexibility through changes in regulated retail tariffs are: 1) expanding time-of-use (TOU) pricing to all residential and small commercial customers, initially on an opt-in basis; 2) exploring seasonal TOU pricing that better aligns with periods of high wind curtailment, in addition to peak generation capacity needs; and 3) coupling retail tariff reforms with identification and encouragement of flexible load technologies, such as electric heating and cooling.

  - In the longer term, more significant changes can be taken to encourage demand-side flexibility: 1) more closely linking regulated retail pricing to spot market prices, to better match pricing with grid conditions in view of challenges of fixing a TOU tariff reflecting the changing pattern of net load with sufficient accuracy and time period; 2) shifting toward prices that encourage efficient use of transmission and distribution systems; and 3) encouraging development of different kinds of demand response and energy storage technologies that enable greater load flexibility.

- ***Enable larger electric heating loads and CHP plants to participate in spot markets (Recommendation 2)***

  - The inflexibility of combined heat and power (CHP) plants that supply heat in the winter is an important driver of wind curtailment in Jilin. Heat storage can increase CHP plant flexibility, but investments in heat storage require a sustainable business model.

  - In Jilin, the Northeast regional ancillary services (A/S) market and State Grid-organized regional spot market for renewable energy are currently the two markets that could generate short-run wholesale market prices. We recommend that Jilin advocate enabling electric boilers, heat pumps, and combined heat and power (CHP) plants in the district heating system to participate in these existing markets and in future spot markets.

    - Spot market prices can encourage CHP plants to efficiently adjust electric output in response to electricity system conditions, and can encourage efficient investments in heat storage, electric boilers, and electric heat pumps for balancing.

- In Jilin, electric boilers that are supplying heat to the district heating network are currently required to buy electricity at retail, rather than wholesale, prices. Relative to revenues from selling heat, these retail prices are currently too high for electric boilers to recover their costs.

- At current heat prices, the most economic use of electric boilers and heat pumps is in reducing wind and solar curtailment during a limited number of hours per year. The size and number of electric boilers and heat pumps that will be cost-effective for balancing wind and solar generation will be relatively small.

▪ In the near term, two incremental steps include: 1) the central government creates a regulatory framework — similar to the existing framework for electricity storage — that enables generator-side electric boilers and heat pumps to participate in the Northeast A/S market; and 2) Jilin agencies engage with CHP plant owners to help them evaluate investment and operational strategies in the Northeast A/S market and future electricity markets, including the cost-effectiveness of heat storage and electric boiler investments and the economics of reducing minimum generation levels for CHP units.

▪ In the longer term, we recommend that evolving market designs enable demand-side participation, and consider the market rules needed to encourage flexible operations by CHP plants. Rules that facilitate demand-side participation in electricity markets will also enable demand response more broadly.

2. <u>Market-Based, Policy-Supported Approaches to Renewable Energy Development</u>

- ***Encourage more efficient use of renewable energy and sharing of renewable energy costs by strengthening the implementation of China's existing system of renewable accommodation goals and supporting the recently announced credit system for renewable energy (Recommendation 4)***

▪ We recommend building on China's existing institutions – provincial, non-binding targets for non-hydro renewable energy and the recently developed framework for green certificates -- to explore options for moving beyond China's national feed-in-tariff (FIT) as the main driver of renewable energy development.

▪ In the near term, explore options for transitioning from a FIT to a mandatory quantity-based support mechanism for renewable energy with strict enforcement.

- The setting of provincial quotas could consider options for encouraging renewable resource poor provinces to procure at least some of their quota from renewable resource rich provinces.

▪ Collaborate with the central government to develop a voluntary market for renewable energy, identifying corporate champions to help expand and support the market.

- Both the mandatory quantity-based support mechanism with strict enforcement and voluntary markets would use competitive procurement and contracts as a strategy for reducing renewable energy costs and making more efficient use of renewable energy.

- In the longer-term, harmonize support policies for renewable energy with China's emerging emissions trading scheme. At higher penetrations of wind and solar generation, emissions pricing may be a more efficient approach to supporting renewable energy.

- ***Develop a regional spot market that creates incentives for efficient use of wind energy (Recommendation 5)***

- Improved regional coordination among system operators offers high potential for reducing costs of integrating higher penetrations of wind and solar generation. In the United States, regional spot markets have enabled states with relatively small electricity systems to achieve larger penetrations of wind generation. Wind curtailment in U.S. independent system operator/regional transmission operator (ISO/RTO) markets is 5% or less of total potential wind generation.

- For non-ISO/RTO regions, regional markets are also emerging in order to benefit from regional balancing of wind and solar generation (e.g., the Western EIM and Southwest Power Pool (SPP)).

- In the near term, incremental steps to expand the volume and transparency of trading in the Northeast A/S market include: 1) formalizing market institutions in publicly available "practical manual" documents that describe rules, responsibilities, and procedures; 2) making data on market results publicly available; and 3) increasing the output range over which coal generators bid into the market to reduce output.

- In the long term, we recommend transitioning the Northeast regional ancillary services market and the State Grid-organized renewable generation spot market trades into a single regional spot market designed in accord with the principles set forth in the Guangdong pilot recommendations.

  - The Northeast regional ancillary services market is more akin to an imbalance or re-dispatch market, like the Western EIM in the United States, than what is commonly considered an ancillary services market in the United States.

  - The State Grid-organized regional renewable spot market more closely resembles the Southwest Power Pool in the United States in its better integration of higher penetrations of wind generation.

- ***Institutionalize renewable resource and transmission planning tools and processes that enable efficient expansion of renewable energy and transmission systems (Recommendation 6)***

  - In China and the United States, the highest quality renewable resources are often located far from load centers. This correlation between resource quality and distance from load centers creates economic tradeoffs. Finding least-cost solutions to these tradeoffs requires innovations in planning, and particularly in regional transmission planning.

- In the near term, consider incorporating and institutionalizing economic modeling into transmission planning through the use of cost-benefit assessments for transmission lines. Using economic optimization models to assess the value of transmission lines will be consistent with wholesale market outcomes.

- In the longer term, consider adopting more formal regional transmission planning processes and harmonizing these with the development of regional spot markets to strike better balance between development of higher and lower quality renewable resources and the transmission investments needed to deliver them.

    - Harmonization implies fewer barriers to power exchange across provinces.

    - Economic analysis in transmission planning, regional scope for planning, and lower barriers to exchange between provinces and regions will favor more efficient use of the existing transmission network, a more optimal balance between lower and higher voltage transmission expansion, and network-to-network rather than point-to-point transmission.

3. Heating Sector Reform and Coordination

- ***Implement a heat tariff reform pilot for new residential buildings (Recommendation 3)***

    - Shifting to consumption-based, cost-reflective tariffs for space heating in Jilin could ease wind curtailment challenges by reducing incentives to over-consume heat and by creating business models for alternative (non-steam) technologies.

    - In the near term, Jilin could pilot heat tariffs and heat metering in new buildings, with different options for metering (e.g., building or individual apartment), thermostat control, and pricing (e.g., cost allocation factors, two-part prices) to gauge effectiveness, feasibility, and customer acceptance.

        - As part of these efforts, we recommend exploring technologies and tariff options for non-steam heating options (e.g., electric heat pumps, ground source heat pumps, electric hydronic heating, ground source heat pumps) in new buildings.

    - In the longer term, transition to consumption-based, cost-reflective heat tariffs for all customers, consistent with the Jilin government's goals.

- ***Develop a long-term, cross-sector energy planning process to coordinate across different government agencies and sectors (Recommendation 7)***

    - In the United States, where states have significant jurisdiction over energy policy and regulation, growing interlinkages between traditionally siloed energy sectors are encouraging the development of statewide, multi-agency planning processes. These long-term planning processes provide a forum for different state agencies to develop a shared vision of the future, and coordinate policy.

- The different Jilin agencies responsible for electricity, building energy, transportation energy, air quality, and water resources could develop an interagency long-term planning process to: 1) develop a shared understanding of environmental goals, policies, and regulations, and 2) create consensus around technology pathways, costs and cost allocation, and strategies for interagency policy coordination.

III. Enhancing Demand Response and Promoting Demand-Side Resources

The Shanghai and Jiangsu pilots aim to develop an enabling policy framework and market system to adopt and expand DR programs for industrial, commercial, and residential customers and to facilitate reform of electricity marketization to elicit value from these programs. This paper offers recommendations for these pilots in three specific topic areas based on U.S. experience: 1) enhancing DR value, 2) sustaining and stimulating greater DR participation, 3) markets and policies for scaling DR development.

1. Enhancing DR Value

- ***Integrate DR into power system dispatch procedures (Recommendation 1)***

  - The value of DR as a dispatchable resource has not been fully recognized in China's grid dispatch procedures. China's grid operators should consider formally integrating DR resources into their operations protocol.

  - Each U.S. bulk power system operator (ISO/RTO) has some form of a reliability-based DR program and clear protocols for dispatching DR under certain operating conditions. China's grid operators should set forth clearly defined conditions under which capacity or emergency-based DR is dispatched to ensure DR is more efficiently utilized.

- ***Maximize DR potential by tapping opportunities beyond peak load reduction (Recommendation 2)***

  - The current focus of DR programs in China's pilots has been primarily on event-based peak load reduction, but DR provides value beyond peak load reduction. DR's value will be maximized if full advantage is taken of DR's ability to respond in real-time to any imbalance on the grid. Such real-time response, however, requires adoption of smart metering, signal communication, and load control technologies.

  - In the United States, DR is used to respond to reliability concerns, to reduce exposure to high market prices, and to play a significant role in integrating renewable energy to the power grid and reduce renewable curtailment.

  - In the near term, consider pursuing DR valuation and potential studies to better understand the diversified roles that DR can play in enhancing the reliability and flexibility of grid operations.

- In the long term, consider developing the necessary institutional frameworks to support use of advanced DR-enabled technologies. We recommend China improve open communication protocols and technology standards for achieving seamless communication and automation.

- ***Create roles and business opportunities for load aggregators to deliver greater DR potential (Recommendation 3)***

  - The focus of load aggregators in China on deploying load sensors and providing end-use customer advisory services has not led to a profitable business model that scales DR.

  - In the United States, DR aggregators pool DR resources across a large number of customers and coordinate these resources to ensure a specified level of energy and/or capacity is always available to a utility or grid operator.

  - Aggregators' value comes from improving customer participation by (1) assuming customers' performance risks, (2) providing resource adequacy and load flexibility to utilities and grid operators, and (3) providing integrated "benefits stacking" services to customers that bundle DR, energy efficiency, distributed generation, and/or energy storage.

  - In the near term, China's DR pilots should consider the following:

    - Leverage the large amount of power use data collected by DR aggregators to help them determine dispatchable load and load that has fast response capability;

    - Encourage DR aggregators to create more diversified service offerings and extend services beyond customer energy efficiency advisory services to coordinating and bundling DR and energy efficiency in order to better serve the needs of power systems.

      As the role of DR aggregator expands, regulators and system operators should continue to examine power system needs holistically to maximize the benefits of DR without causing unintended reductions of the control and coordination of the transmission system or distribution system.

  - In the longer term, China's DR pilots should consider the following:

    - DR aggregators' business models could be expanded to aggregate electric vehicles, behind-the-meter storage, and distributed generation;

    - With higher penetrations of renewable energy in China's grid, DR aggregators' use of fast response DR to provide ancillary service support will become increasingly important;

    - Develop automated load response (autoDR) infrastructure and DR Management Systems, which is critical for deploying fast DR resources, to improve DR efficiency and minimize performance risk.

2. Sustaining and Stimulating Greater DR Participation

- ***Promote more effective tariffs to increase customer response (Recommendation 4)***
  - China's DR pilots could design tariffs to more effectively strengthen time-varying prices and create stronger price signals for inducing retail customer response.

  - In the United States, time-based tariff programs encourage demand responsiveness to system conditions by using time-differentiated retail rates to alter customers' electricity consumption pattern.

  - China should consider taking four incremental steps to expand DR through retail tariffs including:

    - Focus initially on industrial and large commercial customers in reforming retail tariffs to make them more flexible to grid conditions;

    - Create event-based Critical Peak Pricing and set it at substantially higher rates than regular on-peak TOU prices to better reflect the value of load management during critical peaks.

    - Gradually expand Transition TOU pricing to more customer groups, like residential and small commercial customers, which are currently only on a volumetric use- based tiered price structure without time-varying tariffs.

    - Given that changing electricity prices is less flexible in China, provide customers choice on price protection, as a temporary measure to ease transition onto a new tariff, or rate discounts, for vulnerable populations who are adversely affected by volatile bills, when exposed to high-priced events.

  - In the longer term, more significant changes to retail tariffs could be considered:

    - Adopt more dynamic pricing schemes such as variable peak pricing. Design greater seasonal and hourly differentiation in TOU prices to foster demand elasticity;

    - Explore more innovative tariff structures to unlock the "full value" of demand-side resources.

- ***Establish stable cost recovery and funding mechanisms to promote DR as a resource (Recommendation 5)***
  - In China, DR recovery mechanisms have not yet been established. Such a mechanism would allow utilities to recover the costs, including administrative costs, equipment costs, and customer incentives.

  - Energy efficiency (EE) and DR cost recovery mechanisms are intended to make the utility "whole" for expenses related to delivering EE and DR programs. In the United

States, utility program costs are usually recovered from all customers through retail rates or as an explicit surcharge on electricity bills, called a systems benefit charge (SBC). Wholesale market program costs generally are paid for by market participants and beneficiaries.

- In the near term, we recommend the following prioritized actions for establishing DR cost recovery and funding mechanisms:

  - Provide specific central government guidelines on how grid companies can include demand-side expenditures that are deemed cost-effective, in their allowed cost of providing reliable electricity services.

  - Jiangsu's approach is one example where it charges the largest industrial customers a special peak price during certain peak events that is higher than the ordinary TOU peak rate and uses the revenue from the spread to compensate smaller customers who curtail power usage during critical peaks. This approach may be optimized as follows to create more stable funding by (1) increasing the number of participants subject to the special peak price; and (2) exploring a market-driven compensation scheme that enables customers to trade their reduced load to those customers that need to keep their load intact.

- Longer-term interventions could include the following:

  - Leveraging the transmission and distribution (T&D) pricing reform in China to allow utilities to recover cost-effective investments in distributed energy resources (DERs), including DR, in their T&D cost base;

  - Considering creation of ratepayer-supported funding mechanism for DR through a tariff add-on. Ratepayer funding applicable to all ratepayers helps create stable and consistent funding levels that support a robust DR market. Ratepayer funding follows the principle that all users of power benefit from DR that helps to reduce the need for peaker units and/or using fuels at prohibitively high prices, while improving overall system efficiency

- ***Stimulate DR through structured compensation incentives (Recommendation 6)***

  - The China DR pilots offer incentives for actual load reduction, without fixed payments, to reward customers for advanced pledges to adjust load.

  - U.S. compensation incentives seek to elicit effective, predictable responses. Our recommendations to make the compensation schemes of the DR pilots more effective consist of the following in the near term:

    - Create a more flexible voluntary load reduction compensation programs such as demand bidding and scheduled reduction to better accommodate customer needs.

- Create opportunities for customers to receive fixed payments for making advance commitments to load reduction. When obligations are made ahead of DR events, the response is predictable and performance can be guaranteed.

- Replace the universal compensation strategy with more effective options that offer different levels of compensation based on factors such as length of advanced notification, number of called events, and locations of system congestion.

▪ Establish a DR performance assurance system with compliance rules that have effective penalties in place.

▪ In the longer term, a more effective scheme may be established that combines stimulating tariffs and effective compensation to offset the unfavorable impacts of stand-alone compensation programs.

- Relying on multiple options rather than a single one can enhance DR's role as a reliable energy resource in balancing supply and demand because using compensation options in conjunction with more effective retail rates could help ensure customer response.

3. <u>Markets and Policies for Scaling DR Development</u>

- ***Enable DR to be monetized through power markets (Recommendation 7)***

▪ The United States has established the following market structures to enable participation of DR resources and the monetization of DR services:

- ***bilateral agreements*** between DR service providers, like load aggregators, and vertically integrated utilities in regulated environments,

- ***DR auctions*** to enable utilities to acquire DR competitively from DR service providers in order to assist utilities with meeting resource adequacy requirements, and

- ***bidding DR resources into an ISO/RTO*** wholesale market, where it exists.

▪ Some near-term recommendations on how China's DR pilots could begin to develop market mechanisms to scale DR are as follows:

- ***Encourage China's grid companies to procure DR through bilateral agreements with DR aggregators,*** cleared through a centralized power trading system**.**

- ***Provide utilities with options to procure the targeted level of DR resources through a carefully structured DR auction.*** With audits of the offers in the auction, DR auctions would enable utilities to procure DR at competitive prices compared to those reached in bilaterally negotiated contracts.

▪ Some longer term recommendations for monetizing DR through market structures in

China include the following:

- ***Allow DR to participate in newly established "spot markets" to provide ancillary services (e.g., spinning and non-spinning reserves and regulation).*** DR can provide these services with little impact on the customer's use of energy, comfort or convenience due to the short duration of response.

- ***Allow DER, including DR, to participate in competitive wholesale markets.*** If well designed, such markets will provide a level playing field for demand-side options to become viable resources that can compete cost-effectively with supply-side options in providing needed energy, capacity, and ancillary services.

- ***Pursue policy changes to effectively drive large-scale DR deployment (Recommendation 8)***

  - China will benefit by establishing a regulatory framework that sets priorities for utilities to acquire least cost demand-side resources before investing in supply options.

  - U.S. and state policies have various mechanisms to enable demand-side solutions, culminating in the establishment of DR as a resource to make the power markets operate more efficiently.

  - Some near-term recommendations for enhancing China's regulatory framework for DR include the following:

    - Develop a plan with specific measures on how to meet the goal of using DR as a flexible peaking adjustment capability to achieve 3% of maximum load, as set forth in China's Opinion on the Implementation of Orderly Liberation of Power Generation and Consumption Planning.

    - Enhance efforts in standardizing equipment, communication, and operational requirements related to DR to enhance DR inter-operability.

    - Focus on DR related measurement and verification (M&V), which is critical to developing a robust DR market.

  - Some long-term recommendations for the central and provincial governments to consider in building a DR regulatory framework are as follows:

    - Change utilities' supply-focused investment mode by providing a positive financial incentive to utilities for pursuing DR, as a way to avoid initiating new capital investment projects.

    - Establish demand-side resources portfolio standards (DSRPS) that set specific targets, in several formats, for adoption of distributed energy resources, including DR. Target-setting helps create consistent demand and drive the market for DER.

- Consider DER resources in generation and transmission planning. Require utilities to consider DR and power storage investments as alternatives to new peaker units and provide justification for investment. Power sector planning should play an essential role in assessing cost-effective alternatives, including non-wire alternatives.

I. Promoting Electric Power Market Competition and Direct Power Trading

Key Recommendations

- Develop practical approach to wholesale “spot market” that supports efficient dispatch, rational resource compensation, and system flexibility to support renewable energy integration (specific recommendations 1 through 6).
- Ensure that retail-side reforms develop in a way that strengthens “smart” pricing incentives faced by end-users and is sufficiently transparent (specific recommendations 7 and 8).
- Facilitate greater participation of renewable energy resources in markets, through development of the renewable portfolio standard, green certificates, and corporate contracting (specific recommendations 9 and 10).

Pilot Background

The Power Market Competition and Direct Power Trading pilot in Guangdong focuses on a core goal of China’s power sector reform effort: developing electricity wholesale and retail markets. On the wholesale side, Guangdong is developing 1) a “medium- and long-term market” featuring competitively determined annual or monthly contracts between generators and large end users; and 2) a shorter-term “spot market”. On the retail side, Guangdong has been fostering the development of competing retail suppliers. The Cooperation seeks to help local regulators formulate market rules, policies and oversight mechanisms, while promoting the incorporation of clean energy resources, such as renewables and demand-side solutions, in the restructured market system. If designed well, the pilot could lead to a thriving market, support the development of clean energy resources, and help contain the size of electricity bills for consumers.

According to the Guangdong pilot document, the “guiding principles” for this reform include (1) increased competition (at both wholesale and retail levels); (2) environmental protection and energy savings; and (3) integration of “new technologies”.[1] These guiding principles correspond with several basic challenges faced by Guangdong (and China as a whole), in particular:

- improving the overall efficiency of operation of the power sector (dispatch);
- rationalizing excess capacity of coal-fired generation;
- promoting renewable energy integration; and
- meeting ambitious goals for air quality and carbon emissions.

[1] “广东省经济和信息化委 国家能源局南方监管局 关于开展售电侧改革试点的请示”

Specific Recommendations

Here we offer a number of specific recommendations, organized under three separate topics, drawing on U.S. experience, which we believe should be of use as the Guangdong authorities move ahead with their reform efforts.

1. Wholesale "Spot Market" Development

The national 13th Five Year Plan for the Power Sector commits to developing "spot markets" and Guangdong Province is now slated to move ahead with spot market development, as the lead province in the Southern Grid spot market pilot.

In this paper we use a concept of 'spot markets' in line with the U.S. experience with regional transmission operators and independent system operators (RTOs/ISOs).[2] We propose a package of market mechanisms, centered on a 'real-time' market which features locational marginal prices, and produces market clearing prices for each intra-day time period (which in the United States are set based on time intervals of fifteen minutes or less). This package also includes a day-ahead market, as well as mechanisms to rationally compensate provision of ancillary services.

Spot markets, if well designed, can help Guangdong's power sector with several important challenges and provide benefits in terms of reduced emissions and lower costs. More specifically, well-designed spot markets can help with the following:[3]

- **Improving efficiency of system operations**: A "merit order" approach to least cost dispatch is the heart of a well-designed spot market. More specifically, a merit order approach means dispatching available resources (including generation units and demand response) in order of their operating costs, which reduces costs and emissions.
- **Guiding investments toward a more rational mix of resources**: A well-designed spot market will send better signals to support resources needed to minimize investment costs, support reliability, and meet emissions goals.
- **Increasing system flexibility and integrating renewable resources and other new technologies**: A well-designed spot market allows for intra-day fluctuations in wind and solar output to be dealt with flexibly and efficiently.

In the United States, ISO/RTO wholesale electricity markets have been useful in dealing with similar challenges, although new technologies and business models means that 'getting the details right' continues to be a subject of debate. How best to design wholesale and retail markets in order to reduce costs and integrate new technologies continues to be a hot topic in the United

[2] ISOs/RTOs refer to markets in various parts of the United States that are centered on independent system operators (ISOs) or regional transmission organizations (RTOs), two terms meaning, at least for the purposes of our discussion here, practically the same thing: they are independent ("voluntary") organizations that operate the short-term markets and have functional control of the transmission system in order to ensure minute-to-minute coordination of electricity supply with demand.

[3] Spot market implementation is not the *only* way to achieve these things. It would be possible to design a package of administrative mechanisms that would also achieve similar results – and possibly in a more manageable and lower-risk manner, given the Chinese context. For example, some parts of the United States have never implemented ISO/RTO markets, yet have made significant progress with the problems listed here. However, this paper accepts the Chinese government's commitment to spot market implementation as a starting point.

States. For example, there is much discussion about how best to design market rules to allow markets to recognize the range of costs and benefits associated with distributed resources (such as rooftop solar and demand response), and to allow these resources to compete on a level playing field with traditional generators.[4]

Guangdong, and China more broadly, has some conditions that are different from the United States that may present challenges in developing competitive spot markets:

- The history of "annual generation output planning" in China is at odds with a merit order approach. ISOs/RTOs in the United States were developed in the context of an industry that was accustomed to and experienced with merit order dispatch (both within vertically integrated utilities and in electricity "pool" arrangements among these utilities).
- Lack of transparency regarding costs and operating conditions, which can make it difficult for competitors to rationally assess market opportunities.
- A power sector dominated by state-owned entities (SOEs), which may not be motivated in the same ways as profit-maximizing commercial enterprises.
- In periods of excess capacity, the market will make it difficult for relatively inefficient capacity to cover costs, thus giving incentives for some capacity to be retired. This is a rational feature of markets, but may lead to resistance to market reform from generation owners who suffer losses.

Guangdong has been developing and gradually expanding a "medium- and long-term" market (MLT market, also referred to as "direct trading"). This MLT market is organized around competitive annual and monthly contracting between demand-side entities (retailers and large industrial end-users) and generators. It is worth noting that the MLT market itself will do little to improve operations on an hour-by-hour basis. A spot market is needed to rationalize generator compensation and operations at shorter timescales.[5] The intention in Guangdong is to have the MLT market operate alongside the new spot market. However, note that the United States does not have any market structure directly equivalent to Guangdong's medium/long market. Instead, in the United States, longer-term contracting occurs in a variety of forms, with financial contracts agreed between private parties on a wide range of timescales, including much longer durations than those in Guangdong. Generally speaking, in ISO/RTO regions, the system operator is not concerned with the terms of these contracts, as the contracts generally are financial in nature. Moreover, some forward markets in the United States are very active, with trades in forward energy occurring on a daily basis. Finally, all U.S. markets are multi-settlement markets that enable both the pricing of reliability of generation resources and active demand-side participation.

Establish spot market with merit order dispatch based initially on a generator reported operating cost basis (Recommendation 1)

Market design is the process of determining the optimal combination of explicit regulation and market mechanisms to improve economic efficiency. A well-designed spot market will minimize

[4] See "Recommendations 1 and 2 for Jilin's Local Consumption of Renewable Energy Pilot" in this paper series for more discussion of demand response and interaction with spot markets.

[5] See, for example, http://www.raponline.org/wholesale-electricity-markets-pricing-china-reform-going/?_sft_region=china

operating costs (or short-run variable cost) by enabling a merit order approach to dispatching power according to resources' marginal cost.

In the United States, markets feature a merit order approach to dispatch. That is, resources are ranked according to the operating cost associated with each resource, subject to availability and transmission constraints.[6] A key question is how to determine the operating cost of each resource. Any well-designed spot market approach effectively requires generators to disclose their operating costs. In the ISO/RTO context in the United States, when markets are working well, competitive pressure generally *incentivizes* generators to bid prices into the market that are in line with operating costs. That is, competition induces each generator to reveal its operating cost. However, establishing sufficient competition is not an easy task. (We have already noted several particular challenges in Guangdong to establishing effective competition, and we expand on those issues under Recommendation #4.)

In the near term, we suggest that Guangdong officials consider how to establish a spot market that will do a reasonable job of eliciting operating costs and translating these into a merit order. An initial market design should aim to lay the groundwork, over the longer term, for continued improvements in accuracy of information regarding costs.

We suggest policymakers in Guangdong should consider two approaches for establishing a spot market with merit order dispatch. Both approaches feature a merit order, which ranks generation units (and other resources) by operating cost (short-run variable cost). Both approaches also feature a single market clearing price. All suppliers receive, and all loads pay, the market clearing price. This market clearing price is based on the merit order. More specifically, the market clearing price is typically equal to the operating cost of the highest cost generation unit necessary to meet demand.

In the first approach, generators "bid in" reported costs. In this report, we will refer to this approach as a "generator reported cost bid structure". Here, the system operator administratively collects reports from generators to make estimates of the operating cost associated with each generation unit. The system operator then uses these estimates to construct a merit order and set the market-clearing price. These cost estimates are subject to confirmation or audit.

In the second approach, competition induces generators to reveal operating costs. In this paper, we'll refer to this approach as a "generator short-run bid structure". Market participants make competitive bids to sell and buy electricity.[7] If the market is sufficiently competitive, a given generation unit will typically maximize profits by making bids that reflect that unit's operating costs. As in the first approach, the system operator uses this information about operating costs to construct a merit order and set the market-clearing price.

The choice between a generator reported cost bid structure and a generator short-run bid structure will hinge on relative confidence in each approach's ability, among other things, to

[6] A "resource" might be a particular thermal generation unit, but it can also be on the demand-side, for example, customer demand response or distributed generation.

[7] Note that, in U.S. terminology, supply-side resources make competitive "offers". However, in this paper, we will refer to generators as "bidding" into the market.

reveal accurate operating costs, maintain the independence of the market and system operator, and enforce a rigorous system of market monitoring and market power mitigation.

Table 1 below sets forth a high-level summary of the near-term pros and cons of the two approaches.

Table 1. Near-Term Pros and Cons of Two Spot Market Merit Order Approaches

	Generator reported cost bid structure	Generator short-run bid structure
Accuracy/efficiency of merit order	Fair (assuming accurate cost reporting)	Excellent (assuming effective competition)
Risk of market power	Low	Medium
Need for increased sophistication on part of market players	Low	High
Need for increased number of players and diversification of ownership	Low	Medium
Need for increased transparency (e.g., pricing, operational information)	Low	High
Importance of improved auditing or official ability to collect information on operating costs	High	High (as part of market monitoring regime)

A well-functioning generator short-run bid structure may be the gold standard in the long-term – but may not produce the highest degree of improvement in the near term, given China's current institutional characteristics. The generator short-run bid structure requires a market monitoring infrastructure and rules with strong, enforceable penalties for non-compliance, in order to yield efficient outcomes. The alternative generator reported cost bid structure would still have key features (including a market-clearing price) and functions of a spot market. However, the assessment of operating costs in an administrative process, wherein the methods are well-publicized and consistently applied, will help habituate regulators, system operators, and market players to the merit order dispatch approach. Using the generator reported cost bid structure in the near term could be a reasonable precursor to the longer-term adoption of the generator short-run bid structure. In fact, reporting and assessment of costs (recorded in accordance with a uniform system of accounting) can serve as one of the basic foundations of a market monitoring/enforcement regime for the generator short-run bid structure.

The ISO/RTO regions in the United States are currently organized according to what we are calling a "generator short-run bid structure" in this paper. However, the United States has some experience with spot market-like designs that are based on reported costs. For example, ISOs/RTOs evolved in certain cases from “power pools” that had been established in earlier decades to allow for trade between various vertically-integrated utilities. In these pools, the utilities dispatched shared resources according to reported operating costs. These pools were very successful at increasing the efficiency of operations over broader areas, increasing reliability, and reducing costs.

More recently, a region of Colorado has been developing a market mechanism intended to supply imbalance energy, known as “joint dispatch”, based on reported costs and features a merit order and a market clearing price. Instead of competitive bids, the market is based on operating costs reported by generation units and supplied to a data platform “portal”.[8] Despite the lack of bids, this market design is intended to work in much the same way as a market in an ISO/RTO region, in so far as it focuses on the ranking, in real time, of various available resources based on their operating costs and dispatching accordingly. In this joint dispatch case, generation units are dispatched based on reported operating costs, rather than on bids. In addition to providing the basis for dispatch, the cost information collected by the data platform in the joint dispatch example roughly parallels the data collection done by ISOs/RTOs in order to verify estimates (known as “reference levels”) of the operating costs of generation units, which are used by the ISOs/RTOs to judge whether the market is competitive and whether any generators are exercising market power. (See Appendix A. We also discuss market power in Recommendation #4.)

In the near term, it would likely be best for Guangdong to pursue the first approach: implementation of a generator reported cost-bid structure. From a broad perspective, this would be a measured initial approach to the complexities of spot market design. There are several reasons why the generator reported cost-bid structure would be best in the near term:

- It would sidestep the need for robust competition, which U.S. experience with spot markets indicates can be difficult to ensure.
- It would set up the foundational elements relating to operating cost-reporting, locational pricing of inputs and outputs, and market monitoring and market power mitigation.

In short, implementation of the first approach (generator reported cost-bid structure) would set the stage for an eventual move toward the second approach (generator short-run bid structure).

Finally, we note that because pricing determinations are a critical factor in the success of any electricity market design, the details of price formation will require deeper examination both to ensure appropriate performance and efficiency, and to mitigate the potential for market distortions. This includes the need for accurate assessment of all components of operational costs and pricing at the location of energy resource outputs.

Establish an institutional framework protective against interference with merit order dispatch (Recommendation 2)

As we explained in previous sections, a key function of any spot market is to determine the operating costs of various available resources (which may be done through reporting of costs or competitive bidding) and then dispatch available resources in order of their operating cost. This “least cost” approach will minimize costs and reduce emissions.

[8] https://www.oasis.oati.com/PSCO/PSCOdocs/Welch_Testimony.pdf

It is important to guard system operations and market operations against deviations from this approach, which are inefficient and costly from the point of view of the overall system. However, it may be that there is not a sufficient legal and regulatory framework in Guangdong (and China as a whole) to ensure that dispatch decisions are focused on efficient and least-cost outcomes (i.e., to ensure that dispatch decisions follow a least-cost merit order approach, based on reasonably accurate information regarding operating costs). The debate over broad institutional structures for China (i.e., whether or not the dispatch centers are located within the gridco) has been going on for many years.[9] Here we review some institutional options for China.

Looking at the United States, and other countries around the globe, we can identify three broad models of institutional organization.

1. **Independent System Operator:** The U.S. ISO/RTO institutions feature an independent system operator (which also handles market operations) for each ISO/RTO region. The ISO/RTO is not a government agency and does not own any transmission or generation assets. This model stresses the independence of the ISO as a way to ensure that the dispatcher does not discriminate in favor of or against any particular generators or customers regarding grid access. This model evolved in order to serve wide areas in which transmission had been traditionally owned by a number of utilities. In practice, it has been successful: the ISOs/RTOs have in fact been independent and transparent in their actions, and they have met their responsibilities in a non-discriminatory fashion.
2. **System Operator (SO) within a vertically-integrated utility:** In non-ISO/RTO parts of the United States, there is no centralized market and thus no market operator. Instead, the SO function is part of a utility that also owns transmission and generation assets. Broadly speaking, the SO has the incentive, as an integrated utility, to dispatch its own generators in an efficient manner, in order to minimize operating costs. In addition, state regulators, or public utility commissions, generally require least cost dispatch, and the federal regulator, the Federal Energy Regulatory Commission (FERC), requires the separation of the generation business from dispatch decisions pursuant to FERC Standards of Conduct.
3. **SO within a grid company that does not own generation assets but owns transmission assets:** This model is seen in countries such as the United Kingdom and New Zealand, and is sometimes referred to as the "TSO" (transmission system operator) model or as the "transco" model. In it, the grid company (the transmission owner) performs the system operator function, but the grid company does not own any generation assets but owns transmission assets.[10] The market operations function may be handled by the grid company or a third-party entity contracted by the grid company (as long as the grid company or third-party entity is protected from interference from interested parties).

Each model has its pros and cons and here we offer brief observations about these models for China and Guangdong. Regarding the first model, we note that, in the Chinese context, it is less common to have independent non-government organizations acting as "watchdogs" or serving to

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[9] For example, see International Energy Agency (2006) *China's Power Sector Reforms: Where to Next?* Also: SERC (2009) *A Research Report on China's Power Transmission and Distribution System Reform*.

[10] Variations include the approach seen in France, in which a TSO is allowed to own generation, but in a legally separated fashion. See Pollitt, Michael (2008) "The arguments for and against ownership unbundling of energy transmission networks." Downloaded from: https://www.repository.cam.ac.uk/bitstream/handle/1810/194717/0737%26EPRG0714.pdf?sequence=1

coordinate industries. It may be difficult to adequately insulate a stand-alone SO (which would be much smaller than generation companies and grid companies) from interference. However, it may be possible to replicate the U.S. success of ISOs if regulatory officials are committed to ensuring the "independent" aspect of an "independent system operator". Regarding the second model, we believe that it is unlikely that Guangdong would want to take the drastic step of re-integrating generators into a vertically integrated entity, since China has gone to the lengths of separating generation assets from the grid company, as part of the reform efforts launched in 2002. As for the third option, it has the advantage of being similar to the current situation in China – and thus does not require major reforms. On the other hand, we understand there may be an interest in narrowing the range of functions carried out by the grid companies, for political reasons.

Whichever model is chosen, the important objective is to ensure least-cost economic dispatch functions are carried out without improper interference from market participants or other interested parties. We recommend that Guangdong issue rules that require regulatory oversight and review of dispatch decisions and require that the transmission system be operated in an "open" manner, so that it is accessible to any generator that wants to use it. More specifically, in the near term, we suggest new regulations requiring publication of market and dispatch procedures and more detailed information about system conditions on a monthly, daily, hourly, and forecast basis (e.g., clearing prices, congestion re-dispatch, load and wind/solar forecasts, transmission outages, and ancillary services requirements). This is important for fostering efficient operations and supporting competition: transparency (particularly regarding market and dispatch procedure and regarding system conditions) allows market participants to develop an accurate view of conditions and develop effective strategies. Such transparency also supports effective regulation.

Establish a transitional strategy to market prices by limiting transition payments to retiring generation capacity and facilitating measured retirement of excess generation capacity (Recommendation 3)

Given a context of substantial excess generation capacity, any reasonably well-designed wholesale market will send signals to close down generation capacity, particularly generators with higher operating cost (i.e., relatively inefficient generators). These signals will be rational from an economic and environmental point of view, but the owners of the less efficient generation will have incentive to resist reform and may request support to continue operation. The challenge will be to ensure that market signals lead to smooth retirement of unneeded capacity.

The United States faced a somewhat similar scenario in the 1990s, in so far as plans to move toward competitive markets were made in the context (at least in some parts of the country) of generation overcapacity.[11] Large industrial consumers and other end users were eager to have "direct access" to new competitive wholesale markets in which this plentitude of generation capacity would compete to offer low prices. However, the utilities that owned the non-competitive generators argued to regulators for compensation for reduction in the value of their generation assets associated with the implementation of competitive markets.

[11] See Borenstein and Bushnell (2015) "The U.S. Electricity Industry after 20 Years of Restructuring". https://ei.haas.berkeley.edu/research/papers/WP252.pdf

Based on this experience, we suggest the following recommendations. First, starting in the near term, limit compensation (out-of-market payments) to excess capacity. In Guangdong (and China more broadly), where there have been various government policy announcements and warnings cautioning generation companies against investment in excess capacity, it may be ill-advised to pay full compensation for the loss in capital value that will be experienced by various generation owners due to restructuring.[12] This cautious approach to limit compensation will reduce any incentives for ongoing overbuilding of capacity. The idea is to avoid unnecessary interference with market signals regarding overcapacity.

Second, design any compensation in a way that does not prolong the operation of inefficient capacity. Compensation should be limited and constrained to a short, well-defined transition period. It may be best to pay compensation in a lump-sum fashion on condition of retirement. This will provide an incentive for existing inefficient generators to exit the market when appropriate.

Third, develop better long-term regional resource adequacy and reliability planning processes to complement the market. Market design and market outcomes must always be carefully observed to ensure that the market is producing reasonable results in terms of investment, retirements, resources types, flexibility, reliability, emissions, and other considerations. U.S. RTOs/ISOs conduct long-term regional planning and use resource adequacy assessments to "evaluate whether there are sufficient supply- and demand-side resources to meet the aggregated electricity demand…with a specified degree of reliability".[13] More specifically, each RTO/ISO typically conducts annual long-term resource adequacy assessment that covers a ten-year planning horizon, based on "one day in ten years" loss of load expectation principles and seasonal reliability assessments that cover summer and winter every year.[14] The process includes modeling of the resource mix, energy market supply curve, generator outage and availability, economic and emergency demand response resources, load growth, weather uncertainty, and scarcity conditions.[15] In Guangdong's case, if, for example, it is determined that the market is giving incentives to certain resources to shut down, but those resources are deemed necessary for reliability, then 1) there may be need for temporary measures to support these resources; and 2) relevant details of market design should be adjusted. At the same time, it is very important that owners of unnecessary and inefficient resources should not be allowed to make superfluous "reliability" arguments for protection of their assets. The necessary resource adequacy and reliability planning processes will need to develop over time. The National Energy

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[12] http://m.companies.caixin.com/m/2017-01-17/101044635.html
http://news.bjx.com.cn/html/20170112/803056.shtml
http://www.jsdpc.gov.cn/zixun/tzgg_1/201605/P020160506368498872942.pdf
http://www.ndrc.gov.cn/zcfb/zcfbtz/201604/t20160425_798979.html
http://zfxxgk.nea.gov.cn/auto84/201609/t20160923_2300.htm

[13] NERC (2008) "Reliability Assessment Guidebook".
http://www.nerc.com/docs/pc/ragtf/Reliability_Assessment_%20Guidebook%20v1.2%20031909.pdf

[14] North American Electric Reliability Corporation (NERC). 2014. *Essential Reliability Services Task Force: A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability.* Princeton, NJ: North American Electric Reliability Corporation.
http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Concept%20Paper.pdf.

[15] Pfeifenberger, Johannes, Kathleen Spees, Kevin Carden, Nick Wintermantel. 2013. "Resource Adequacy Requirements: Reliability and Economic Implications"
https://www.ferc.gov/legal/staff-reports/2014/02-07-14-consultant-report.pdf

Administration's 2016 *Power Sector Planning* Regulation represents a good starting point on which to build.

Develop a rigorous framework for market monitoring, market power mitigation and enforcement (Recommendation 4)

Recommendation 1 suggests first implementing a spot market with a "generator reported cost bid structure", with a shift to a competitive spot market ("generator short-run bid structure") over the long term. Here, we discuss how the generator reported cost bid structure can serve as the foundation for a market monitoring, market power mitigation, and enforcement structure that will support the longer-term implementation of the competitive spot market.

The information collected under the generator reported cost bid structure is very similar to the information that must be collected to support monitoring and enforcement under a bid-based market. In other words, should Guangdong decide to implement a generator reported cost bid structure in the near term, we recommend simultaneous efforts to ensure that the cost-reporting mechanisms can evolve into a robust market monitoring and enforcement structure. Should Guangdong instead choose to implement a competitive generator short-run bid structure in the near-term, then the need for attention to market monitoring and enforcement will take on additional urgency.

The nature of electricity production and demand can create opportunities for the exercise of market power in a competitive generator short-run bid structure) spot market. This can mean excessive prices for consumers. It also undermines the information content of the bids: in a well-functioning competitive market, the bids should reveal the operating cost of each generator, allowing the system operator to form an efficient dispatch order. In the presence of market power, however, generators no longer have proper incentives to reveal their true operating costs and can engage in behavior (such as withholding of capacity) that is detrimental to consumers.

Even the most competitive markets in the United States and elsewhere depend upon vigilant market monitoring and enforcement to give policymakers and the public confidence that the market is functioning as intended. Regulators must have means of determining, correcting, and punishing (and thus discouraging) market power abuses. A bid-based spot market should not be implemented until a robust and effective market monitoring and enforcement structure is in place.

It is important to recognize that, in the U.S. experience (and that of other countries), attention to market power has focused on 'spot market' transactions. Competitive spot markets are susceptible to market power because electricity supply and demand must be matched on a second-by-second basis (with limited storage resources). In addition, transmission conditions fluctuate throughout the day, so that a single generator may sometimes find itself isolated from its competitors and able to act as a temporary "monopoly". Even if this monopoly status lasts only for a few hours or less, the generator may be able to increase prices substantially and cause significant harm to consumers. In contrast, the degree of concern about market power in longer term markets (e.g. the "medium and long-term" market in Guangdong) is somewhat less as the longer-term nature means it is less likely for a generator to find itself advantageously insulated from competition.[16] That said, excessive consolidation or effective monopolies in the generation

[16] In U.S. mandatory forward markets - such as capacity markets - there is extensive market power mitigation.

sector may prove problematic and may undermine the benefits of competition in not just the short-term energy markets but also the medium and long-term markets.

In the United States, FERC exercises oversight over wholesale markets and has developed regulations to address potential market power. This includes:

- Requirements for the establishment of market monitors in each ISO/RTO.
- Rules and procedures for rapid identification of and remedial action against market power.

In designing effective market monitoring and mitigation for Guangdong, an important step will be a deeper understanding of generator costs and establishment of a register and reporting mechanism for those costs in which the methodology is consistent across companies. The information collected under the generator reported cost-bid structure to estimate operating cost should be pursuant to books and records maintained in accord with a consistent set of accounting rules (e.g., FERC's Uniform System of Accounts).

For eventual implementation of a generator short-run bid structure, we recommend establishing tests for market power and codifying mitigation responses. This should include:

- Procedures to determine whether any given generator has the *potential* to exercise market power, based on analysis of existing competitors and grid constraints. (For example, FERC's "three pivotal suppliers test".)
- Assessment of the degree of concentration of ownership in the market.
- Procedures to determine whether any generator has *actually* been able to submit bids that exceed the generator's own true operating costs by a significant margin. (Referred to by FERC as "conduct and impact tests".)
- An estimate of the true operating cost ("reference level" in FERC terminology) of a generator in question. The practice of estimating operating costs could grow from the methods established to survey and verify cost data under a 'reported-cost' spot market model that is based on requirements to maintain books and records in accordance with a uniform system of accounting. (See Appendix A.)
- Clear assignment of responsibility and authority to a designated regulatory agency to conduct these tests, make assessments, "mitigate" offers down to an estimate of incremental costs (as required by established rules), and impose additional penalties (including possible denial of 'market-based rate authority') in a transparent fashion.
- Establishment of market monitors. In the U.S. ISO/RTO experience, *independent* market monitors have played key roles in promoting transparency, reporting on the overall functioning of the market. In each ISO/RTO, the monitor issues very detailed quarterly and annual reports. In these reports, the monitors provide data and commentary on market developments, resource costs, and scope for and evidence of market power. Monitors also make recommendations for rule changes in order to improve the market.

Enlarge spot market footprint to create a regional market with integrated multi-province economic dispatch (Recommendation 5)

In Guangdong (and China more broadly), there is a legacy of provincial balancing, tax, and investment policies that favor use of in-province resources. In the United States, a crucial way to increase power system flexibility is increasing the footprint of the balancing areas (BAs). This typically involves physical interconnection of adjacent BAs through enhancement of the transmission network, but short of that, much of the benefits can be achieved by cooperation between BAs.[17] Larger market footprints provide access to a greater diversity of generation and loads, as well as a larger pool of reserves. In terms of renewable integration, larger footprints can significantly reduce the variability of renewables due to geographic smoothing.[18] The aggregated regulation reserve requirements and resulting system operation costs can be significantly reduced with an expanded market footprint.

Levels of BA-coordination typically go from reserve sharing (a first step) to coordinated scheduling to coordinated operation of a fully integrated market. Even if an integrated market is unattainable, facilitating the first two steps of cooperation between BAs can also increase operating efficiency, reduce the variability risks, and the impacts of uncertainty (including that associated with wind, solar, and hydro output), reduce total operation cost and is conducive to more efficient inter-regional transmission planning and investment. Reserve sharing means that two or more BAs collectively maintain, allocate, and supply the reserves required for each BA. Coordinated scheduling occurs on both day-ahead unit commitment and short-term dispatch and load following. It can take many forms, and may involve establishment of an information exchange system for generator availability and cost, a monitoring system and financial compensation mechanisms for energy exchanges and transmission usage, and transmission availability calculation at the operating timescale.[19] The Energy Imbalance Market (EIM) is one form of coordinated scheduling that has emerged in the Western United States. The e BAs in China may choose to adopt other forms of coordination that work under the Chinese political and economic paradigm as an interim step towards a fully integrated regional market.

In the near term, we recommend Guangdong implement an effort to analyze the benefits of fully integrated multi-province economic dispatch. In the medium term, an EIM may be a feasible step in this direction. In the longer term, we recommend Guangdong work to implement a fully integrated multi-province balancing area and spot market in the Southern Grid footprint. (Recommendation 5 for the Jilin pilot also discusses development of a regional market.)

Design ancillary services based on system reliability and stability requirements (Recommendation 6)

Ancillary services (A/S), as defined by the Federal Energy Regulatory Commission (FERC) in Order 888, are services necessary to provide basic transmission to customers while ensuring continued electric service reliability. In the United States, one principle for electricity market design is that prices for energy and for various ancillary services should be unbundled, where possible, to minimize averaging of costs. This is because averaged prices (e.g., for congestion, reserves, or other costs) do not send the correct price signals for the supply of needed services.[20]

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[17] Milligan, Michael, Bethany Frew, Ella Zhou, Douglas J. Arent. 2015. *Advancing System Flexibility for High Penetration Renewable Integration*. NREL/TP-6A20-64864. Golden, CO : National Renewable Energy Laboratory

[18] Muzhikyan, A., A. M. Farid and T. Mezher, "The impact of wind power geographical smoothing on operating reserve requirements," 2016 American Control Conference (ACC), Boston, MA, 2016, pp. 5891-5896.

[19] NREL. 2015. *Balancing Area Coordination: Efficiently Integrating Renewable Energy into the Grid*. Golden, CO: NREL. https://www.nrel.gov/docs/fy15osti/63037.pdf

[20] O'Neill, R.P. U. Helman, P.M. Sotkiewicz, M.H. Rothkopf, W.R. Stewart. 2001 "Regulatory Evolution, Market Design and Unit Commitment." In Hobbs et al. (eds.) *The Next Generation of Electric Power Unit Commitment Models*. New York, NY: Kluwer Academic Publishers.

If the cost of A/S and energy is bundled together (as it is currently in most of China's power system) the system operator does not have the ability to shop for the lowest cost A/S products that can meet the performance requirement. This means higher overall system operation cost and risk for sustained reliability violations.

Another key principle is that ancillary services markets should be resource neutral and payments should be performance based. This means that all resources, on both the supply side and the demand side, should be allowed to compete in the market on an equal footing, as long as they can provide the reliability services and meet required parameters (e.g., notification period, response speed, response depth, and length of performance).[21] Commonly used types of ancillary services in the United States include regulation, load following, spinning reserve, non-spinning reserve, and supplemental reserve (see Appendix B). FERC Order 755 stipulates that the payments to ancillary service providers, regardless of technology, should be based on performance. This means that, for example, equal provision of frequency regulation from two supplies (be it a wind generation unit or a battery storage) should receive the same compensation. For U.S. ISOs/RTOs, some of the ancillary service products are operated according to the North American Electric Reliability Corporation (NERC) reliability standards (e.g. CPS1, CSP2, DCS, BAL-003) and/or Western Electricity Coordinating Council (WECC) voltage stability guidelines.[22]

In the near-term, we recommend that Guangdong initiate a process to define a set of needed ancillary services, based on system reliability studies. This will depend on the characteristics of Guangdong's system and may not be identical to FERC's definitions. The identified services should then be unbundled and separately priced. The prices for ancillary services can be set in administratively, based on their respective costs. In the mid- to long-term, Guangdong should establish ancillary service mechanisms for each service, and allow all resources, including renewables and demand-side resources, to compete in the ancillary services market based on their reliability contributions. This parallels Recommendation 1 for the spot market for energy, where we suggest that market mechanisms be first developed on a generator reported-cost bid structure, evolving over the longer-term into a generator short-run bid structure.

1. Retail Market Development

From an overall perspective, U.S. "best practice" with retail competition suggests that the retail market should be designed with the following principles in mind:

- Fairness— the market doesn't favor one group of customers at the expense of others.
- Economic efficiency—the market reveals to retailers and customers the economic value (cost) of their consumption decisions (e.g., enables demand response).
- Sustainability—the market enables customers to make informed decisions about their consumption choices (e.g., disclosure of fuel and emissions data, availability of

[21] Milligan, Michael, Bethany Frew, Ella Zhou, Douglas J. Arent. 2015. *Advancing System Flexibility for High Penetration Renewable Integration*. NREL/TP-6A20-64864. Golden, CO: National Renewable Energy Laboratory

[22] Zhou, Zhi, Todd Levin, Guenter Conzelmann. 2016. "Survey of U.S. Ancillary Services Markets" Energy Systems Division, Argonne National Laboratory. http://www.ipd.anl.gov/anlpubs/2016/01/124217.pdf

resource-specific— "green"—products, and clear pricing and product terms and conditions).

This section looks at ways to support these principles as Guangdong's retail market develops.

Encourage "smart" pricing in the new competitive retail market (Recommendation 7)

Experience in the United States shows that the *structure* of prices offered to retail customers is very important. It influences the behavior of the customers, as well as the retailers and other industry participants. The challenge is to influence these participants in a "smart" way – which we define here as giving participants incentive to behave in ways that help meet provincial and national objectives for the power sector and the environment.

Guangdong already has a number of pricing policies that are "smart", according to this definition, including time of use (TOU) prices for the industrial sector, tiered prices for residential consumers, and differential prices for industrial consumers. These policies date from before the decision to move toward retail competition. In fact, China is arguably ahead of the United States in a number of these areas. The challenge will be to protect and innovate on these smart price structures as Guangdong moves to expand retail competition.

Here we look at a few aspects of smart pricing and how they may be applied in Guangdong as it moves toward retail competition.

Time-varying and dynamic rates: The underlying costs of providing electricity vary hourly and seasonally – for example, with fluctuating demand, grid, and weather conditions – and ideally customers should be exposed to some signal associated with this fluctuating cost. As we saw in the last section, a well-designed spot market will reflect these fluctuating costs at the wholesale level. However, having a well-designed spot market is not enough; attention is needed to how retail end-users perceive those wholesale costs. Revising the way customers are charged for energy use can help persuade customers to manage loads during key hours, helping the grid operators manage the grid as demand and supply fluctuate throughout the day.

Both the United States and Guangdong have experience with TOU price structures. However, there is some discussion in parts of the United States about moving toward even more flexible and dynamic "real-time pricing" (RTP) rate designs. Under this pricing, the customer faces prices that fluctuate hour-by-hour, directly linked to the real-time changes in the wholesale cost of electricity. To date, typically only large industrial or commercial customers have been on RTP, but the option may be increasingly available to lower-volume customers, who will perhaps have "smart" appliances that monitor and react automatically to changes in price. For example, a smart refrigerator, water heater or electric vehicle might be set to automatically defer energy use to periods of the day when the prices are low.

Tiered prices: Tiered prices charge residential consumers according to monthly blocks of consumption, so that higher-consuming households face higher marginal rates, which encourages energy savings while protecting low-income households. China now has tiered pricing across the country for residential customers, in contrast to the United States, where only some states have adopted this structure. The challenge for Guangdong will be to protect this useful aspect of rate design in the context of retail competition.

Differential prices: Under China's "differential pricing" policy, some industrial and commercial customers are classified according to the energy efficiency of their production processes, and relatively inefficient customers are charged higher unit prices, thereby giving them a double incentive to improve the efficiency of their power usage (double because, being inefficient, they are already using more electricity per unit of industrial output – e.g., kWh/ton of aluminum – than their competitors; the increased price per kWh then further increases their cost penalty).

Emissions pricing: Guangdong has piloted a carbon trading scheme and China plans to implement a national scheme soon. The United States also has regional experience with emissions trading (e.g., in the northeast and California).

In light of these observations, we make several recommendations for Guangdong. In the near term, Guangdong should:

- Maintain differential pricing by continuing to require that end-users be subject to such prices, according to their energy consumption classification, even if they are allowed access to competing retail offerings.
- Carefully manage the early stages of the transition to a well-functioning national carbon emissions pricing scheme. It may be that the national scheme will be implemented in such a way that the emissions cap is gradually tightened and emission prices likewise rise gradually, taking perhaps several years to reach an optimal level (i.e., where externalities are fully internalized). Meanwhile, a rapid shift to retail competition will put sharp downward pressure on end-user prices, particularly in a context of generation overcapacity. The challenges will be to avoid a contradiction in these two trends and to smooth the transition. Strengthening the differential pricing policy will also help in this regard.

In the longer term, we recommend measures to foster more flexible and dynamic real-time pricing. Such measures include allowing retailers access to real-time spot market prices (once the spot market is in operation), reviewing minimum performance requirements and technical specifications for advanced metering infrastructure (with an eye toward better enabling retailers to access real-time metering data from customer premises), and creating wholesale market mechanisms that value and reward flexibility in demand as well as supply.

Promote retail market transparency by developing standardized procedures for information disclosure (Recommendation 8)

Consumers cannot make rational purchasing decisions without access to timely and accurate information about products and services. In the case of electricity, information about emissions, prices, terms and conditions, and the resources in the retailer/supplier's generation portfolio (i.e., information about the relative shares of the various resource types serving the customer) are important to various consumers. However, retail companies may be reluctant to provide this information. This is in part because information disclosure raises marketing and administration costs, but also because lack of transparency can sometimes allow retailers to take advantage of customers who have little understanding of the market.

Certain U.S. states have adopted information disclosure rules with which all suppliers must comply. Typically, they require that the suppliers provide periodic notices to consumers on the characteristics of their supply portfolios: costs, resource types, and emissions and other environmental data. Availability of such information has helped support consumer demand for cleaner sources of electricity.

Appendix C shows one example of a standardized information disclosure form that Texas has used as part of its requirement that all retailers offer uniform information disclosure.[23] This includes a requirement for standardized reporting of:

- average price per kilowatt-hour (according to consumption blocks);
- contract terms and cancellation fees;
- sources of power generation, by fuel type; and
- emissions per kWh.

This approach has been useful in bringing a degree of transparency and comparability to the wide range of retail options available in the market place. In the United States, this has been primarily geared toward increasing transparency for residential and small-to-medium size commercial firms. However, standardized disclosure, including of historic and real-time pricing, can also be useful in the context of larger end-users – including those interested in procuring renewable resources on a long-term basis.

In the near term, we recommend that Guangdong develop a standardized format for information disclosure, including contract terms, pricing and emissions content, for all retailers and suppliers. In the longer term, Guangdong should implement a regulatory structure to oversee and test the veracity of retailers' information by conducting random audits, by which their public declarations are compared to their actual resource portfolios (both owned and purchased). This may be integrated with the "green certificate" scheme (see Recommendation #9), so that retailers claiming renewable energy content should be required to show acquisition of corresponding renewable energy credits.

2. Facilitate greater participation of renewable energy[24] resources in the market

U.S. experience includes a number of efforts to support renewable energy participation in electricity markets. These include policy-driven approaches, such as resource portfolio standards, as well as initiatives stemming from corporate interest in supporting renewable energy resources. Here we look at two sets of recommendations to help better support renewable energy in the context of the markets discussed in the first two topic areas.

Design an effective renewable portfolio standard, supported by green certification (Recommendation 9)

China's provincial RPS (Renewable Portfolio Standard) is established under *Guiding Opinions on the Establishment of a Guidance System for Targets of Renewable Energy Development and Utilization*.[25] It stipulates that green certificates will be used as the tracking and auditing mechanism for meeting the renewable energy targets. However, the document does not offer sufficient details on how the RPS and green certificates will be implemented. For example, the

[23] Texas has the highest degree of retail competition in the United States, as measured by the state-wide proportion of total load supplied from an alternative supplier.

[24] Renewable energy here refers to energy produced from renewable sources such as wind, solar, biomass, and geothermal. Because hydropower is already a huge part of the power source in China, we do not include hydro in the discussion of incentivizing renewable energy.

[25] 国家能源局(NEA). 2016. "国家能源局关于建立可再生能源开发利用目标引导制度的指导意见" [Guiding Opinions on the Establishment of a Guidance System for Targets of Renewable Energy Development and Utilization]/

document provides little detail regarding obligated parties, verification mechanisms, and penalties for non-compliance. As a result, several provinces, including Guangdong, are behind in meeting their renewable accommodation goals as of 2016.[26]

In the United States, RPS requirements drove 60% of all non-hydro renewable generation growth and 57% of all new non-hydro renewables capacity growth since 2000.[27] In the United States, RPS is implemented as a requirement on load-serving entities (including retail electric suppliers) and is typically backed with some form of penalties for non-performance and accompanied by a tradable green certificates (known as RECs; renewable energy credits) program to facilitate compliance. For example, California SB-350 requires the California Public Utilities Commission (CPUC) to adopt a schedule of penalties for non-compliance and stipulates that the penalties cannot be collected in rates it charges the customers.[28] Some states have alternative compliance payment (ACP) mechanisms (in case the retailer or utility is unable to acquire RECs). The ACP is typically set at a level higher than both the estimated competitive market cost of purchasing a REC and the cost of meeting the requirement by generating the required renewable energy.[29] The RECs used to meet RPS requirements typically have higher prices than RECs in a voluntary market. In states with specific RPS targets for solar, regulated entities use "solar RECs" (SRECs) to demonstrate compliance. SRECs are generally pricier than other compliance RECs due to the relatively high cost of solar generation compared to other renewable generation technologies.[30]

Based on U.S. experience with RPSs, we suggest that Guangdong implement a clear point of obligation for the RPS, by placing it on load-serving entities (including retailers and large end-users) and also impose strict penalties for non-compliance to ensure the effectiveness of RPS. (See also our Recommendation #4 for the Jilin pilot.) RPS should be designed in a way to help Guangdong meet its renewable energy and economic development objectives. The newly-launched green certificate system in China has the potential to support the realization of RPS goals, but there must be a central authority with the capacity to handle tracking and certification, as well as a well-developed contractual framework.[31] For a province with high electricity demand and relatively low utility-scale solar and onshore wind potential such Guangdong, there is the potential to meet high RPS goals through purchasing out-of-province renewable energy or RECs. Adding a solar component to RPS would add complexity and require additional levels of verification, but could help promote solar generation that is aligned with China's economic interests. Therefore, Guangdong should consider adding a solar RPS to promote its in-province solar generation, especially distributed PV development. Over the long-term, we recommend coordinating the RPS with an improved resource planning process (for example, the RPS may become more stringent as the costs of renewable energy falls and could be key to lowering renewable subsidies).

[26] 国家能源局(NEA). 2017. "国家能源局关于 2016 年度全国可再生能源电力发展监测评价的通报" [Notice of 2016 national renewable energy generation monitoring and evaluation]/

[27] Barbose, Galen. 2016. *U.S. Renewables Portfolio Standards 2016 Annual Status Report*. Berkeley, CA: Lawrence Berkeley National Laboratory.

[28] California Legislature SB-350.

[29] U.S. Department of Energy (DOE). 2017. "Renewables Portfolio Standard." Accessed July 12, 2017. https://energy.gov/savings/renewables-portfolio-standard-0

[30] SREC Trade. 2017. "SREC Markets." Accessed July 12, 2017. http://www.srectrade.com/srec_markets/

[31] Hamrin, Jan, Ryan Wiser, Seth Baruch. 2015. *Designing a Renewables Portfolio Standard: Principles, Design Options, and Implications for China*. Center for Resource Solutions.

Enable corporate procurement of renewable energy (Recommendation 10)

In the United States, corporate end users—in order to hedge against electricity price volatility and demonstrate corporate sustainability commitments—have driven a substantial amount of new renewable energy development. About 1,000 corporations have voluntarily committed to use over 30 million MWh of green power annually.[32] Corporate renewable energy procurement occurs through a number of mechanisms, including power purchase agreements (PPAs) and green tariffs.[33]

A PPA is a contract in which the off-taker (e.g., a corporate customer) agrees to buy power for a pre-determined period (e.g., 20 years) at a contractually determined price from a renewable energy generator. This shifts project finance responsibilities and investment risks from the customer to the generator.[34] This shifting of risk facilitates the investment in renewable energy by these corporate customers, for which owning and operating renewables is typically not a core business. Many PPAs are structured as a contract for differences (CfD): the off-taker provides a price guarantee to the renewable energy generator but does not directly receive the electricity, only the RECs. The electricity generated is then sold in the wholesale market. According to the CfD, if the market price turns out to be higher than the contractual price (known as "strike price"), then the generator pays the difference to the off-taker. In contrast, if the market price turns out to be lower than the strike price, the off-taker pays the difference to the generator. In this way, both parties are able to establish a needed long-term hedge over future energy price uncertainty.

Another option for corporate customers interested in renewable energy is to purchase "green power" under a "green tariff" from their utility or competitive retail energy provider. The utility or retailer will typically use green power revenues to procure and retire unbundled RECs, purchased from online markets, third-party agents, or directly from a generation facility. In some cases, the revenues will go to cover the costs of utility-owned renewables generation. Retailers offer green power at different prices than non-green ("undifferentiated") power; the prices are fixed for a specified period, usually two years or less. Regulated utilities offer green power as a premium, added to the customer's retail rate for undifferentiated electricity. These premiums averaged 1.7 cents per kilowatt-hour in the United States in 2014.[35]

In China, near-term options to support corporate purchase of renewable energy include distributed generation, the newly-launched green certificates mechanism, and utility green tariff combined with verifiable green energy tracking. Under the green tariff, the incumbent utility (e.g. Guangdong Grid) may offer renewable electricity to interested corporate consumers at a cost-based price (which, typically, is a different rate than the normal tariff). Corporations can choose from these options when shopping for renewable electricity. We recommend that

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[32] O'Shaughnessy, Eric, Chang Liu, Jenny Heeter. 2016. *Status and Trends in the U.S. Voluntary Green Power Market (2015 Data)* NREL/TP-6A20-67147. Golden, CO : National Renewable Energy Laboratory

[33] Other mechanisms in use in the United States include direct corporate ownership of renewable generation.

[34] Hassett, Timothy C., and Karin L. Borgerson. 2009. *Harnessing Nature's Power: Deploying and Financing On-Site Renewable Energy*. Washington, D.C.: World Resources Institute.; David Gardiner & Associates. 2013. *Power Forward: Why the World's Largest Companies are Investing in Renewable Energy*. Geneva: World Wildlife Foundation; World Business Council for Sustainable Development. 2016. *Corporate Renewable Power Purchase Agreements*. Geneva: World Business Council for Sustainable Development.

[35] National Renewable Energy Laboratory, *Status and Trends in the U.S. Voluntary Green Power Market (2014 Data)*, October 2015. Downloaded from http://www.nrel.gov/docs/fy16osti/65252.pdf.

renewable generators, including out-of-province resources, be encouraged to participate in the MLT market. In the absence of a spot market with a multi-provincial footprint (see Recommendation #5) this participation in the MLT market will not be a “silver bullet” to solve barriers to interprovincial trade. However, it should create additional pressures in support of interprovincial trade. In the medium to long term, we suggest the government should allow corporate customers to engage in PPAs (which would generally be structured as CfDs) with renewable generators or procurement through third-parties. This can greatly contribute to renewable energy accommodation and meet the corporate demand for green power. As we argue in Recommendation #5, it is also useful for Guangdong and its neighbors to develop integrated wholesale markets so that projects are developed where it is most economic to do so, looking across provinces. Through the use of market forces and RPS, Guangdong can change its generation mix while optimizing the system to provide adequate electricity at cost effective prices.

Appendix I-A: Reporting/Estimating Generator Operating Costs

The two examples of reported costs mentioned in the main text include the "joint dispatch" example and estimation of reference costs in RTO/ISO markets. This appendix provides a general overview of the kinds of costs used in RTO/ISO reference costs (pursuant to FERC's Uniform System of Accounts).

The details can be fairly complex. For example, one ISO, PJM, maintains a 128-page manual on "Cost Development Guidelines", which sets out reference level cost calculation methodologies in detail.[36] Here we offer an overview of key cost input categories that are typically reported by, or calculated on behalf of, generating units.[37]

Net heat rate curve: A net heat rate is the energy content of a thermal generator's fuel input (e.g., in China in grams coal equivalent, or gce) divided by its net power output (e.g., in MW).[38] Net heat rates vary with a unit's level of net output, defining an average net heat rate curve. In other words, a net heat rate curve shows a generator's net thermal efficiency at different levels of output. Net heat rates are often reported per unit energy (MWh) rather than power (MW).[39]

Fuel price: Fuel prices may be based on a contract delivered price or a reference spot market fuel price plus transport costs. Fuel prices should be on an energy basis (e.g., in China in yuan/kCal terms).[40]

Variable operating and maintenance (O&M) costs: Variable O&M costs include other costs that vary with output, including non-capital expenditures for regular maintenance and the cost of chemicals, water, and other inputs used in operation. Variable O&M costs are often reported in output terms (e.g., $/MWh).

Startup cost and no-load costs: Startup cost is the cost of fuel, chemicals, water, and other inputs required to start a generating unit. For steam units, startup costs depend on the condition of the boiler (hot, warm, cold) and are often reported as a function of cooling time in cost per start ($/start) terms. No-load, or minimum load, costs are the fuel cost required to maintain the unit's minimum level of output. No-load costs are in dollar per hour ($/h) terms.

Emissions rates: An emissions rate is the average level of emissions (e.g., grams of SO_2) for a given level of net output (e.g., kWh) or for startup. Emissions vary with a unit's level of net output, defining an emissions rate curve. Emissions rates can be calculated from continuous emissions monitoring devices or using a fuel emission factor (e.g., grams SO_2 per kCal of coal) multiplied by the net heat rate curve.

Emissions price: Emissions prices are the price of tradeable emission permits or fees, in terms of cost per unit of emissions (e.g., dollars per ton CO_2). The price of tradeable permits could be based on a varying publicly-available market price or on a fixed price reported by generators.

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[36] http://www.pjm.com/~/media/documents/manuals/m15.ashx

[37] Information available on the Colorado "Joint Dispatch" approach is available here: https://www-static.bouldercolorado.gov/docs/PSCo_Open_Access_Transmission_Tariff-1-201611041332.pdf

[38] Net power output is the gross power produced by the unit minus any power consumed at the plant to run auxiliary and pollution control equipment.

[39] In this case, the two are equivalent. An energy heat rate assumes a constant power output averaged over one hour.

[40] Determination of fuel costs for coal fired generation is relatively straightforward. Other resources (like pondage hydro) have more complex cost determinants, with daily, weekly or longer energy limits.

Review and approval: The above information is periodically reviewed and approved by the ISO/RTO, with details varying across ISO/RTO regions. In the "joint dispatch" example, the agreement allows any generator to audit the records of any other generator "to the extent reasonably necessary to verify the accuracy" of the data provided to the platform. If an audit turns up inaccurate reporting, then the generator that reported inaccurate information is required to make up the resulting overpayment or underpayment (if any).[41]

FERC's Uniform System of Accounts: Companies subject to FERC regulation are required to maintain their books and records in accordance with FERC's Uniform System of Accounts (USofA).[42]

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[41] In the case of a dispute, parties could potentially bring the issue to court. Clearly, China would have to find its own approach to auditing and penalties, suitable for its own legal system and institutions. It may be better in the Chinese context to have a government agency responsible for auditing and penalties.

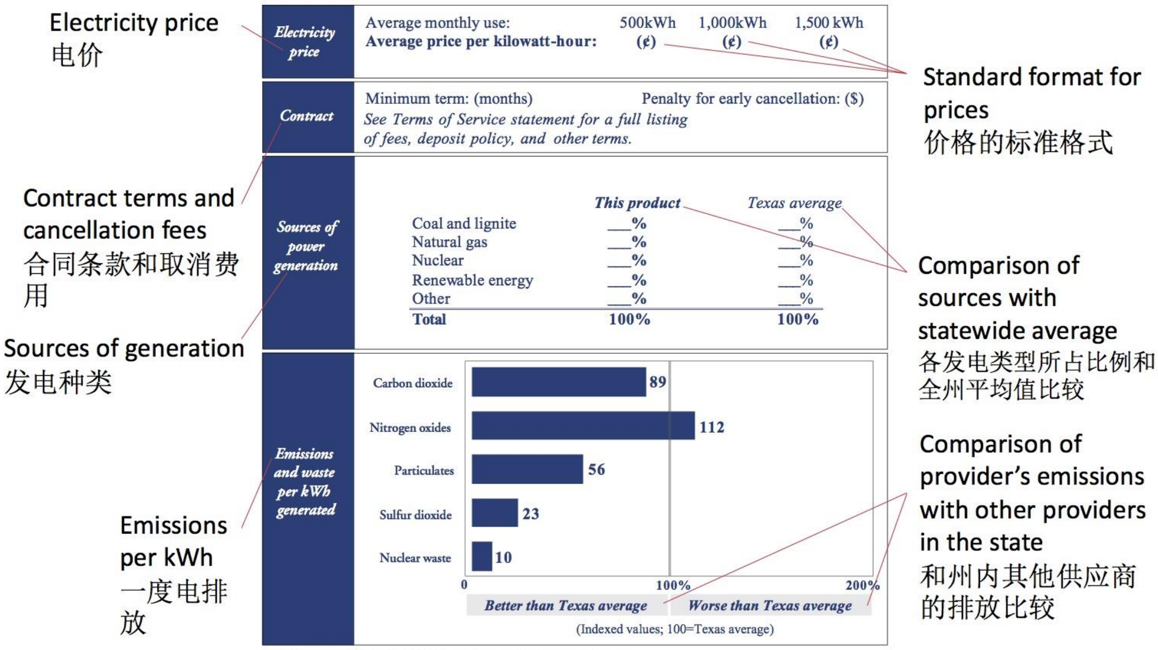
[42] An official paper copy of the USofA can be obtained from the U. S. Government Printing Office. The telephone number is 1-866-512-1800 (toll-free) or 202-512-1800 (in the DC area). Ask for Code of Federal Regulations, Title 18, Conservation of Power and Water Resources, Parts 1-399, Revised as of April 1 of the current year. They can also be purchased online at http://bookstore.gpo.gov/. The accounting requirements for jurisdictional electric companies, natural gas companies, oil pipeline companies, and centralized service companies are found at Parts 101, 201, 352, and 367, respectively.

Appendix I-B: Types of Ancillary Services Commonly Used in the United States

Regulation	• Used to manage the minute-to-minute differences between load and resources and to correct for unintended fluctuations in generator output to comply with NERC's Real-Power Balancing Control Performance Standards (BAL-001-1, BAL-001-2)
Load following	• Follow load and resource imbalance to track the intra- and inter-hour load fluctuations within a scheduled period
Spinning reserve	• On-line resources, synchronized to the grid that can increase output in response to a generator or transmission outage and can reach full output within 10 minutes to comply with NERC's Real-Power Balancing Control Performance Standards (BAL-001-1, BAL-001-2) • Usually utilized after a contingency • Generally provides a faster and more reliable response • Variable generators may be non-spinning, but can be utilized as spinning reserves
Non-spinning reserve	• Similar in purpose to spinning reserve; however, these resources can be offline and capable of reaching the necessary output within 15 minutes of being called • Usually utilized after a contingency
Supplemental reserve	• Resources used to restore spinning and non-spinning reserves to their pre-contingency status • Deployed following a contingency event • Response does not need to begin immediately

Source: North American Electric Reliability Corporation (NERC). 2014. *Essential Reliability Services Task Force: A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability*. Princeton, NJ: North American Electric Reliability Corporation.

Appendix I-C: Example of Texas Electricity Facts Label



Source: Public Utility Commission of Texas

2. Increasing the Local Consumption of Renewable Energy

Key Recommendations

- Support new business models for demand- and supply-side flexibility, through retail tariff design and expanding access to spot market pricing (recommendations 1 and 2)
- Develop a spot market for the Northeast region, based on emerging regional markets (recommendation 4)
- Create a pilot for heat tariff reforms in new residential buildings (recommendation 3)
- Encourage coordination of long-term energy planning across different government agencies and sectors (recommendation 7)

Pilot Background

Jilin has been very successful in encouraging the development of wind power. However, this success has been accompanied by a rapid rise in provincial wind energy curtailment. Wind curtailment rose from 15% in 2014 to more than 30% in 2015 and 2016.[43] A key driver of wind curtailment in Jilin is the use of inflexible combined heat and power (CHP) plants to provide heat during the winter, which limits the amount of wind power that the electricity grid can absorb.

Jilin's Local Consumption of Renewable Energy pilot seeks to reduce provincial wind curtailment through a series of measures focused on making the province's electricity and heating sectors more flexible to accommodate wind generation. The pilot has a goal of reducing curtailment by 1 terawatt-hour (TWh) per year during the 13th Five-Year Planning period.

More specifically, the pilot includes seven measures: (1) electric heating with wind power; (2) flexibility retrofits for thermal units; (3) substitution of thermal generation with wind generation; (4) expansion of electric heating pilots; (5) direct purchases of wind for large customers; (6) renewable energy microgrids; (7) hydrogen production from wind power.[44]

In addition, several other central, regional, and provincial initiatives will influence the pilot's success. These include: (i) the Northeast regional ancillary services (A/S) market, in which wind and nuclear generators pay coal generators to reduce their output below a certain level;[45] (ii) regional spot market pilots for renewable energy organized by State Grid Corporation, where renewable generators can sell "incremental" energy that cannot be absorbed locally to other provinces; (iii) central government minimum operating hour mandates for wind and solar generators, as well as provincial efforts to implement these guarantees; (iv) a retail electricity market pilot in Jilin, similar to the Guangdong pilot; and (v) ongoing heat tariff reforms in Jilin.

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[43] Data are from the National Energy Administration's (NEA's) *Wind Interconnection and Operation* (风电并网运行情况) series.

[44] These seven elements are from the Jilin Energy Bureau's presentation during the October 2016 study tour. The original pilot proposal included two additional measures: optimizing energy structure and improving operations (优化电源结构和改善运行方式) and increasing export capability from resource-rich regions (加强可再生能源富集地区电力外送能力). See Jilin Energy Bureau, *Jilin Provincial Plan for Local Consumption of Renewable Energy Pilot* (吉林省可再生能源就近消纳试点方案), 2016, http://www.ndrc.gov.cn/zcfb/zcfbtz/201604/W020160411375906107931.pdf.

[45] This "ancillary services" market more closely resembles an imbalance or re-dispatch market than what would be commonly thought of as an A/S market in the United States.

High levels of wind curtailment in Jilin are a symptom of several economic and coordination challenges within the province's energy sector. Reducing wind curtailment will require multiple strategies, as recognized in the design of Jilin's pilot.

Specific Recommendations

1. Business Models for Electric Heating and Flexible Loads

Our recommendations focus on the importance of price reform and data-based planning to: (a) increase local consumption of renewable energy (*local consumption*) and (b) make more efficient use of renewable energy across Northern China (*regional consumption*).

We recommend seven main actions, categorized as to whether they focus on local or regional consumption of renewable energy:

1) Investigate new designs for retail electric tariffs that create business models for electric heating and other flexible electric loads (*local consumption*);
2) Enable larger electric heating loads and CHP plants to participate in spot markets (*local consumption*);
3) Implement a heat tariff reform pilot for new residential buildings (*local consumption*);
4) Encourage more efficient use of renewable energy and sharing of renewable energy costs by strengthening the implementation of China's existing system of renewable accommodation goals and supporting the recently announced credit system for renewable energy (*local consumption*);
5) Develop a regional spot market that creates incentives for efficient use of wind energy (*regional consumption*);
6) Institutionalize renewable resource and transmission planning tools and broader processes that enable efficient expansion of renewable energy and transmission systems (*regional consumption*);
7) Develop a long-term, cross-sector energy planning process to coordinate across different government agencies and sectors (*local consumption*).

The remainder of this section describes each of these recommendations in greater detail.

Investigate new designs for retail electricity tariffs that create business models for electric heating and other flexible electric loads (Recommendation 1)

Shifting electric loads to better match the timing of wind generation can reduce wind curtailment. Without incentives, customers are unlikely to invest in technologies that enable this greater flexibility and responsiveness in electricity demand — electric water heating, electric space heating, electric vehicles (EVs), distributed generation, customer-side batteries. New retail tariff designs can help to provide incentives, by creating business models for new technology manufacturers and retail customers. In addition to load shifting that reduces wind and solar curtailment, new retail tariff designs can also encourage more demand response (DR). Recommendation 4 for the Jiangsu and Shanghai DR pilots discusses design of retail tariff that enables DR.

In the United States, states with rising penetrations of wind and solar generation are beginning to explore new retail tariff designs. These new designs aim to increase the flexibility of demand, by expanding the number of customers that have access to time-of-use (TOU) pricing and the granularity of TOU prices. For instance, California plans to transition all utility customers to TOU prices by 2019.[46] California is also considering greater seasonal and hourly differentiation in TOU pricing to better match demand and underlying hourly costs, which are increasingly influenced by solar generation (Figure 1).

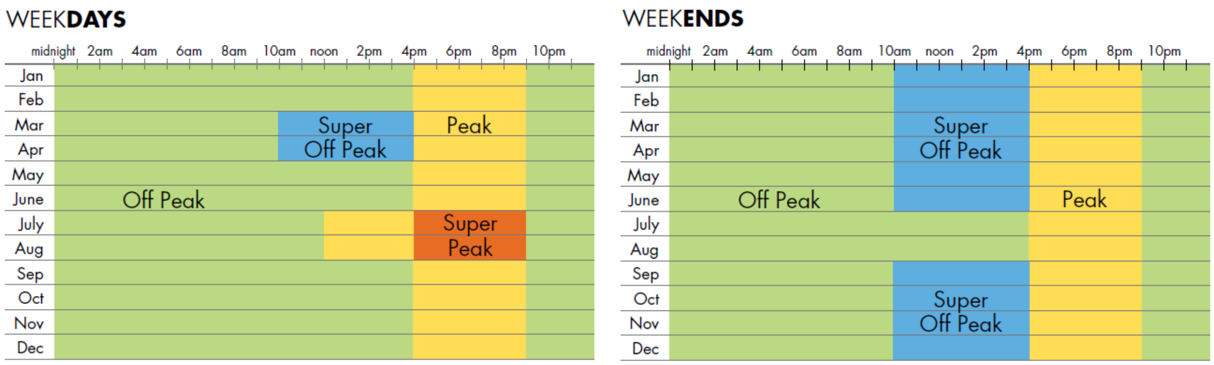

Figure 1. California independent system operator (CAISO) proposal for seasonal TOU tariffs in California[47]

Other states are considering more significant changes in retail tariffs that more closely align with the marginal costs of the electricity system. For instance, as part of its Reforming the Energy Vision (REV) proceeding, New York is exploring an opt-in, three-part retail tariff that balances marginal cost-based prices with cost recovery for grid infrastructure.[48] In principle, prices that are based on marginal costs provide the most economically efficient signal for investments in demand-side flexibility. However, marginal cost-based electricity prices tend to be volatile and historically customers have had limited ability to respond to these prices. New "smart" technologies are now beginning to enable greater price response.

These proposed retail tariff designs have not yet been implemented, and thus their effectiveness and efficiency is still uncertain. For instance, it is not clear how much time differentiation in TOU prices would be needed to align TOU prices with wind generation. However, changes in retail tariffs can, in principle, be a low-cost, low-risk means of increasing electricity system flexibility because they do not require additional investment, can be designed around predictable times of wind or solar generation, and can be structured to better target customers that can make use of them through opt-in designs.

Jilin currently has traditional on-peak and off-peak pricing for industrial customers and residential electric heating in single family homes. Building on these tariffs, we recommend that

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[46] "Utility" here refers to companies whose retail prices are regulated by the California Public Utilities Commission. As of 2017, most electricity customers in California still received service from one of the state's three major electric utilities. For more on California's retail tariff reforms, see http://www.cpuc.ca.gov/General.aspx?id=12154.

[47] Figure is from CAISO, "Matching Time-of-Use Rate Periods with Grid Conditions Maximizes Use of Renewable Energy," https://www.caiso.com/Documents/MatchingTimeOfUsePeriodsWithGridConditions-FastFacts.pdf.

[48] This three-part "full value" tariff includes a customer charge ($/month), a charge to recover historical transmission and distribution (T&D) system costs ($/kW-year), and a marginal cost-based charge that includes hourly market costs and estimated marginal costs for T&D. For more on this tariff, see Energy and Environmental Economics, 2016, "Full Value Tariff Design and Retail Rate Choices," http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BA0BF2F42-82A1-4ED0-AE6D-D7E38F8D655D%7D.

Jilin explore expanded access and new designs for retail tariffs, in order to create business models for investments in demand-side flexibility.

In the near term, we recommend three incremental steps to increase demand-side flexibility through changes in regulated retail tariffs: (1) expanding TOU pricing to all residential and small commercial customers, perhaps initially on an opt-in basis; (2) exploring seasonal TOU pricing that better aligns with periods of high wind curtailment, in addition to peak generation capacity needs; and (3) coupling retail tariff reforms with identification and encouragement of flexible load technologies, such as electric heating and cooling.

In the longer term, we recommend more significant changes to encourage demand-side flexibility: (1) more closely linking regulated retail pricing to spot market prices, to better match pricing with grid conditions; (2) shifting toward prices that encourage efficient use of transmission and distribution systems; and (3) continuing to encourage the development of different kinds of demand response and energy storage technologies that enable greater load flexibility.

Enable larger electric heating loads and CHP plants to participate in spot markets (Recommendation 2)

The inflexibility of CHP plants that supply heat in the winter is an important driver of wind curtailment in Jilin.[49] Electric boilers and electric heat pumps can increase electricity system flexibility during the heating season, but are generally an expensive way to supply heat. Heat storage can increase CHP plant flexibility, but investments in heat storage require a sustainable business model. Spot market prices can encourage CHP plants to efficiently adjust electric output in response to electricity system conditions, and can encourage efficient investments in heat storage, electric boilers, and electric heat pumps for balancing.

In Jilin, electric boilers that are supplying heat to the district heating network are currently required to buy electricity at retail, rather than wholesale, prices. Relative to revenues from selling heat, these retail prices are currently too high for electric boilers to recover their costs.

Figure 2 shows breakeven electricity prices — the average electricity price required for electric boilers to recover their costs — for electric boilers, at different prices for heat (yuan per gigajoule) and with different utilization hours for the boiler (see Appendix II-A). Even at very high boiler utilization, *average* breakeven electricity prices will likely be less than 0.10 yuan/kWh.

[49] During the winter, CHP plants generate electricity as a “byproduct” to heat. This fixed electricity output from CHP plants crowds out wind generation.

Figure 2. Breakeven electricity price for electric boilers (y-axis, yuan/kWh) as a function of wholesale heat price (x-axis, yuan/GJ), at different annual operating hours for the electric boiler (lines)

Figure 2 suggests that electric boilers will only be cost-effective if: (1) electricity prices are very low, such as during periods of wind curtailment when spot prices will be zero or negative; or (2) heat or emissions prices are much higher, which could be the case if air quality regulations were to lead to restrictions on using coal to generate heat. If heat prices continue to be at current levels, the most economic use of electric boilers and heat pumps is in reducing wind and solar curtailment during a limited number of hours per year (1, in the above two conditions). By revealing when these hours occur, spot market prices can provide signals to guide efficient investments in electric boilers and heat pumps used for balancing wind and solar generation. The size and number of electric boilers and heat pumps that will be cost-effective for balancing wind and solar generation will be relatively small.

The United States does not have a large district heating network. Denmark's energy systems provide a better illustration of how spot market prices can guide investments in, and the operation of, electric boilers, heat pumps, and heat storage. In Denmark, electric boilers and heat storage are installed at the CHP facility. Spot market prices shape CHP owners' decisions about how much heat storage and electric boiler capacity to invest in, and how to optimally operate heat storage, electric boilers, and the CHP plant. When prices are high, CHP plants increase their electric and heat output, storing excess heat in heat storage. When prices are low, CHP plants reduce their electricity and heat output, use heat from heat storage to meet their heating loads, and those that have electric boilers buy electricity from the market to run their boilers. Minimum generation levels for CHP units in Denmark can be as low as 10% of nameplate capacity. Appendix II-B provides details on Danish experience.

In Jilin, the Northeast A/S market and State Grid-organized regional spot market for renewable energy are currently the two markets that could generate short-run wholesale market prices. We recommend that Jilin advocate enabling electric boilers, heat pumps, and CHP plants in the district heating system to participate in these existing markets and in future spot markets.

In the near term, we recommend two incremental steps: (1) that the central government create a regulatory framework — similar to the existing framework for electricity storage[50] — that enables generator-side electric boilers and heat pumps to participate in the Northeast A/S market; and (2) that Jilin agencies engage with CHP plant owners to help them evaluate investment and operational strategies in the Northeast A/S market and future electricity markets, including the cost-effectiveness of heat storage and electric boiler investments and the economics of reducing minimum generation levels for CHP units.

In the longer term, we recommend that evolving market designs enable demand-side participation, and consider the market rules — for instance, rules around self-scheduling and price floors[51] — needed to encourage flexible operations by CHP plants. Rules that facilitate demand-side participation in electricity markets will also enable demand response more broadly.

2. Market-Based, Policy-Supported Approaches to Renewable Energy Development

Encourage more efficient use of renewable energy and sharing of renewable energy costs by strengthening the implementation of China's existing system of renewable accommodation goals and supporting the recently announced credit system for renewable energy (Recommendation 4)

China's national feed-in tariff (FIT) policy for renewable energy has been very successful in encouraging growth in renewable generation capacity and the development of a renewable energy industry. However, going forward the policy mechanisms to support the continued development of renewable energy in Jilin, and in China more broadly, are unclear. Two critical, interrelated questions are how to encourage efficient use of renewable energy and how to fairly allocate its costs.

In the United States, a combination of mandatory state renewable portfolio standards (RPS), voluntary markets for renewable energy, and regional markets for electricity have driven the rapid expansion, cost allocation, and efficient use of renewable energy. In 2000, wind and solar generation accounted for more than 5% of total generation in only 1 state (California); by 2015, wind and solar accounted for more than 15% of generation in 10 states (Figure 3).[52] Currently, RPS requirements and voluntary markets account for about 60% and 40%, respectively, of new renewable energy installations.[53]

[50] NEA, 2016, *Notice on Encouraging Storage Participation in the "Three Norths" Ancillary Services Market* (关于促进电储能参与"三北"地区电力辅助服务补偿（市场）机制试点工作的通知), http://zfxxgk.nea.gov.cn/auto92/201606/t20160617_2267.htm.

[51] "Self-scheduling" occurs when generators or their scheduler bid a quantity with no corresponding price into a system operator spot market, typically meaning that the generator is a price taker. This practice can limit system operators' ability to economically dispatch the system. Lower price floors provide a means to encourage economic bidding, by making self-scheduled generators pay the system operator to remain online when prices are negative.

[52] These ten states include California, Colorado, Iowa, Idaho, Kansas, Minnesota, North Dakota, Oklahoma, South Dakota, and Vermont.

[53] See, for example, National Renewable Energy Laboratory (NREL), "Voluntary Green Power Procurement," http://www.nrel.gov/analysis/green-power.html.

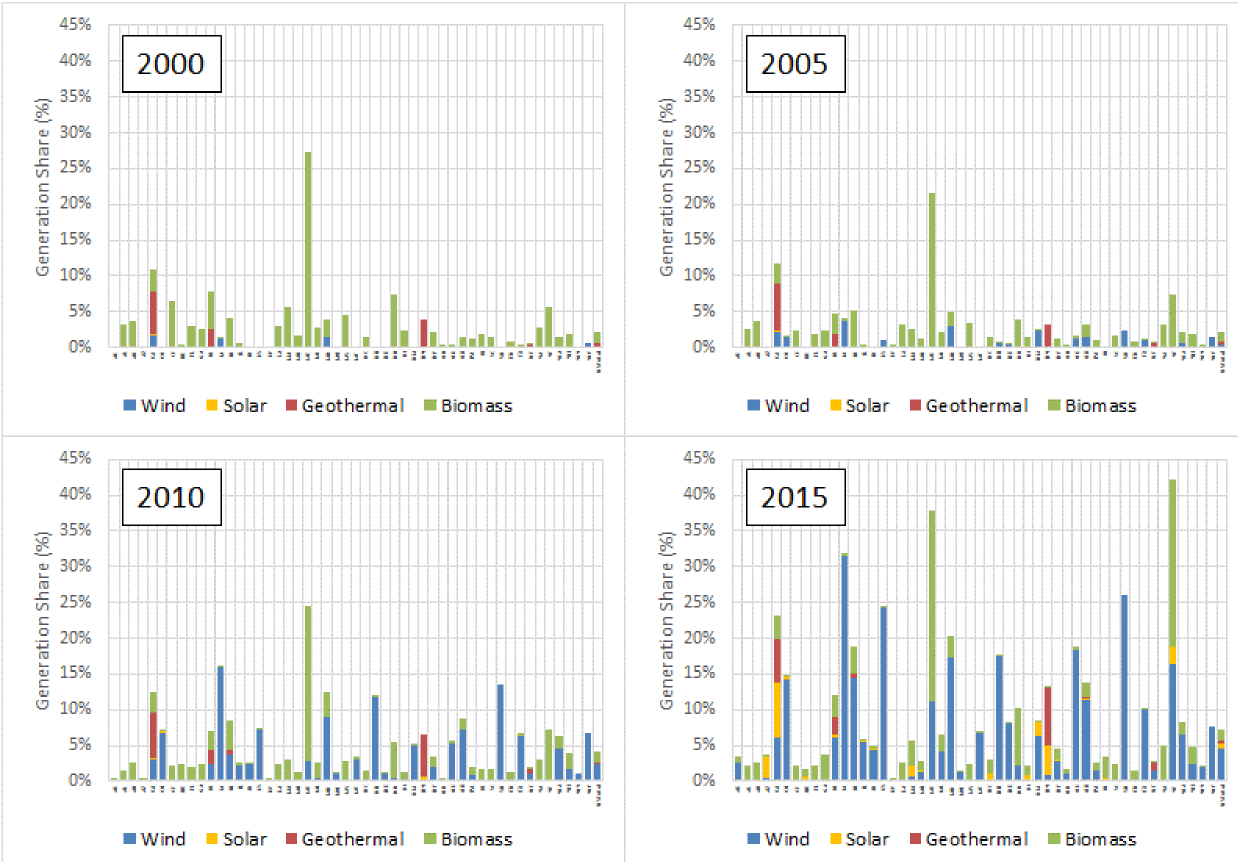

Figure 3. Share of renewable generation in total generation by U.S. State, 2000-2015[54]

Both RPS requirements and voluntary markets provide incentives for efficient use of wind and solar generation. RPS targets create a cost for wind and solar energy curtailment: the cost of procuring more renewable energy to replace curtailed renewable energy and avoid noncompliance penalties. Additionally, contracts within both RPS programs and voluntary markets typically contain terms that allocate the costs of curtailment and provide incentives for efficient use. Regional electricity markets have played a role in supporting RPS standards and voluntary markets, as discussed in the next recommendation.

Increasingly, renewable energy procurement in the United States is being driven by the declining costs of renewable generation technologies. For instance, as Figure 4 shows, the average price of utility-scale solar PV power purchase agreements (PPAs) in the United States fell from around $140/MWh (1.0 yuan/kWh) in early 2010 to less than $40/MWh (0.3 yuan/kWh) in early 2017. Prices for new wind PPAs in some regions are below the fuel cost of natural gas generation, indicating that it is cheaper to build new wind generation to supply energy and use existing gas generation as a backup capacity resource. This reduction in costs is expected to limit the consumer impacts of state RPS and greenhouse gas (GHG) emission reduction goals. For

[54] Data are from Energy Information Administration (EIA), "Net Generation by State by Type of Producer by Energy Source," https://www.eia.gov/electricity/data/state/annual_generation_state.xls.

instance, in California meeting over 70% of total electricity sales with renewable energy in 2030 is expected to increase total electricity costs by around 3%.[55]

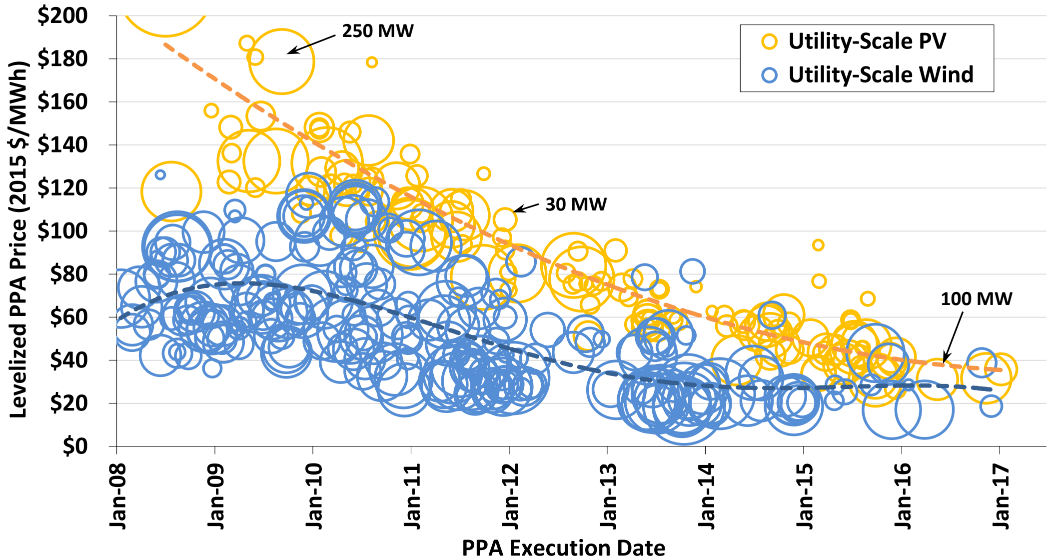

Figure 4. PPA price trends for utility-scale PV and wind in the United States, 2008-2017 (Bubble Size Indicates PPA Capacity, in MW)[56]

In addition to the FIT, China already has provincial targets for non-hydro renewable energy, though they are non-binding. The NDRC, Ministry of Finance, and NEA also recently developed the regulatory framework for a system of renewable energy credits (RECs).[57] We recommend building on these existing institutions to explore options for moving beyond the FIT as the main driver of renewable energy development.

In the nearer term, we recommend that the central government continue to explore options for transitioning from a FIT to a mandatory quantity-based support mechanism for renewable energy with strict enforcement. The setting of provincial quotas could consider options for encouraging renewable resource poor provinces to procure at least some of their quota from renewable resource rich provinces. We recommend that Jilin work with the NDRC to support the development of a voluntary market for renewable energy, identifying corporate champions to help expand and support the market. Both mechanisms would use competitive procurement and

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[55] This increase in costs is relative to a baseline scenario where renewable energy accounts for one-third of California's total electricity sales. Incremental costs for the "greater than 70%" scenario are from CPUC and E3, 2017, "Preliminary RESOLVE Modeling Results for Integrated Resource Planning at the CPUC," http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/17/CPUC_IRP_Preliminary_RESOLVE_Results_2017-07-19_final.pdf; Baseline costs are from E3, 2014, Investigating a Higher Renewables Portfolio Standard in California, https://www.ethree.com/wp-content/uploads/2017/01/E3_Final_RPS_Report_2014_01_06_ExecutiveSummary-1.pdf.

[56] Figure is from Lawrence Berkeley National Laboratory.

[57] NDRC, MoF, and NEA, 2017, *Notice on Pilot Implementation of a System for Issuance and Voluntary Procurement of Green Power Certificates* (关于试行可再生能源绿色电力证书核发及自愿认购交易制度的通知), http://www.nea.gov.cn/2017-02/06/c_136035626.htm.

contracts as a strategy for reducing renewable energy costs and making more efficient use of renewable energy.

In the longer-term, we recommend harmonizing support policies for renewable energy with China's emerging CO_2 cap-and-trade program. At higher penetrations of wind and solar generation, emissions pricing may be a more efficient approach to supporting renewable energy, by reducing the high frequency of negative pricing.

Develop a regional spot market that creates incentives for efficient use of wind energy (Recommendation 5)

One of the most robust conclusions from the growing body of research on renewable energy is the potential for improved regional coordination among system operators to reduce the costs of integrating higher penetrations of wind and solar generation.[58] Expanding the geographic area over which wind and solar generation are balanced tends to reduce their variability, reduce their forecast error, and increase the available pool of hydro and thermal generation for balancing. The result is lower wind and solar energy curtailment and lower total electricity costs.

In the United States, regional spot markets have enabled states with relatively small electricity systems to achieve larger penetrations of wind generation. For instance, in Iowa, Kansas, and South Dakota wind generation exceeds 20% of total statewide generation, despite the fact that these states have relatively small populations and loads.[59] Utilities in all three states are part of a regional transmission organization (RTO), which allows wind generation to be efficiently balanced across the larger RTO region rather than just within the state. Wind curtailment in U.S. independent system operator markets is 5% or less of total potential wind generation (Figure 5).[60]

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[58] See, for example, Michael Milligan and Brendan Kirby, 2010, *Impact of Balancing Areas Size, Obligation Sharing, and Ramping Capability on Wind Integration*, http://www.nrel.gov/docs/fy07osti/41809.pdf; GE Energy, 2010, *Western Wind and Solar Integration Study: Executive Summary*, http://www.nrel.gov/docs/fy10osti/47781.pdf; EnerNex Corporation, 2011, *Eastern Wind Integration and Transmission Study: Executive Summary and Project Overview*, http://www.nrel.gov/docs/fy11osti/47086.pdf; Energy and Environmental Economics, 2014, *Investigating a Higher Renewable Portfolio Standard in California*, https://ethree.com/documents/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf.

[59] Data are from Energy Information Administration (EIA), "Net Generation by State by Type of Producer by Energy Source," https://www.eia.gov/electricity/data/state/annual_generation_state.xls.

[60] Among independent system operators, the Midcontinent Independent System Operator (MISO) had the highest level of estimated wind curtailment in 2015, at 5.4%. See U.S. Department of Energy, 2016, *2015 Wind Technologies Market Report*, https://emp.lbl.gov/sites/all/files/2015-windtechreport.final_.pdf.

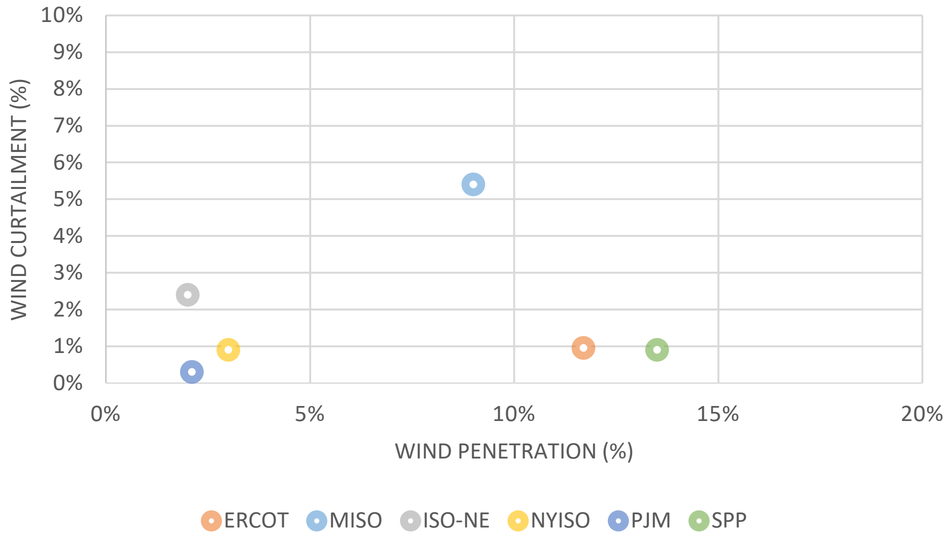

Figure 5. Wind curtailment and wind penetration for U.S. independent system operators, 2015[61]

For regions that are not part of an RTO, such as the Western United States, the potential benefits of regional balancing of wind and solar generation have led to the creation and expansion of regional markets. The Western energy imbalance market (EIM) was created in 2014 to improve regional dispatch efficiency and more efficiently use wind and solar generation. Utilities in Colorado and Wyoming are currently considering joining the Southwest Power Pool (SPP), in part to better integrate higher penetrations of wind generation.

In Northeast China, the A/S market and State Grid-organized regional renewable spot market trades are potential precursors to a regional spot market in the Northeast. The Northeast A/S enables wind and nuclear generators to pay coal generators for providing additional economic and physical flexibility. The State Grid regional renewable spot market allows provinces within a region to determine a price for surplus wind energy that can be exported to neighboring provinces. These initiatives mirror some of the function of a regional spot market, by enabling regional economic dispatch that lowers overall operating costs for the region. We recommend that the central government support these efforts in the near term, transitioning them into a single regional spot market over the longer term.

In the near term, we recommend incremental steps to expand the volume and transparency of trading in the Northeast A/S market, including: (1) formalizing market institutions in publicly available "practical manual" documents that describe rules, responsibilities, and procedures;[62] (2) making data on market results publicly available; and (3) increasing the output range over which coal generators can bid into the market to reduce their output.

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[61] Wind curtailment percentages are percent of potential wind generation; data are from the U.S. Department of Energy, 2016, *2015 Wind Technologies Market Report*, https://emp.lbl.gov/sites/all/files/2015-windtechreport.final_.pdf. Wind penetration percentages are the percent of wind generation in total net generation; data on wind penetration percentages are from various system operator reports.

[62] For an example, see the CAISO's business practice manuals at https://www.caiso.com/rules/Pages/BusinessPracticeManuals/Default.aspx.

In the longer term, we recommend transitioning the Northeast A/S market and renewable generation spot market trades into a single regional spot market. The market design principles and approaches described in the Guangdong pilot recommendations can also inform the design of a regional spot market in the Northeast.

Institutionalize renewable resource and transmission planning tools and processes that enable efficient expansion of renewable energy and transmission systems (Recommendation 6)

In China and the United States, the highest quality renewable resources are often located far from load centers. This correlation between resource quality and distance from load centers creates economic tradeoffs among renewable resource costs, transmission costs to deliver renewable electricity to loads, and the cost of integrating renewable generation onto the grid. Finding least-cost solutions to these tradeoffs is requiring innovations in planning, and particularly in regional transmission planning.

In the United States, transmission planning was historically oriented around physical reliability standards. Federal regulation now requires transmission providers to participate in a regional planning process that evaluates regional transmission investments on the basis of economic and public policy benefits, in addition to reliability.[63] This regional planning process must also have a robust method and clear rules for allocating transmission costs among transmission providers, often across state boundaries. Allocation methods are based on quantitative analysis.

Broadening the scope for evaluating transmission investments has required RTOs and other transmission providers to incorporate scenario-based forecasts of renewable energy development into their transmission planning. These forecasts generally attempt to identify renewable resource portfolios that have the lowest combined resource and transmission costs, and identify transmission investments that are robust across different scenarios and support renewable energy development goals. Examples include Transmission Economic Assessment Methodology (TEAM) used by CAISO Multi Value Project (MVP) portfolio analysis used by MISO.[64]

The United States' increasingly sophisticated wholesale markets should not overshadow the role of long-term, coordinated planning in renewable generation and transmission investment. Market prices facilitate valuation of new renewable energy projects and allocation of costs and benefits across multiple regions, but investment decisions are still often made through long-term planning processes. In these processes, models are often used to simulate market outcomes.

In China, geographic discrepancies between resources and loads have been reconciled, in part, by building long-distance high voltage transmission lines to connect renewable resource zones in renewable-rich provinces to load centers in eastern and southern provinces. During the 13th Five-Year Plan (2016-2020), however, the NDRC and NEA shifted emphasis to support renewable resource development closer to load centers. We recommend that, as the 13th Five-Year Plan evolves, the NDRC and NEA encourage transmission planners to adopt economic analysis tools

[63] FERC, 2011, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order 1000, https://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf.
[64] For CAISO, see https://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology.pdf; for MISO, see https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MVPAnalysis.aspx.

that support a balance between local renewable resource development and long-distance transmission, and that are consistent with anticipated market designs.

In the near term, we recommend incorporating and institutionalizing economic modeling into transmission planning through the use of cost-benefit assessments for interprovincial transmission lines. This modeling could be done in existing planning processes (e.g., Five-Year Plans). Before spot market pricing exists, economic optimization modeling could be based on estimated generator costs. Using economic optimization models to assess the value of transmission lines will be approximately consistent with wholesale market outcomes.[65] More institutionalized use of economic models in transmission planning could build on the significant improvements in modeling capacity in China in recent years.

In the longer term, we recommend adopting more formal regional transmission planning processes and harmonizing these with the development of regional spot markets.[66] From both a modeling and an operational perspective, harmonization implies fewer barriers to power exchange across provinces. The combination of economic analysis in transmission planning, a regional scope for planning, and lower barriers to exchange between provinces and regions will tend to favor more efficient use of the existing transmission network, a more optimal balance between lower and higher voltage transmission expansion, and network-to-network rather than point-to-point transmission. This combination will also help to strike a better balance between the development of higher and lower quality renewable resources and the transmission investments needed to deliver them.

3. Heating Sector Reform and Coordination

Implement a heat tariff reform pilot for new residential buildings (Recommendation 3)

Space heat for most buildings in Jilin appears to be supplied and paid for on the basis of floor area rather than user-controllable, metered demand. Additionally, prices for heat do not fully reflect supply costs, particularly coal and pollution control costs. A significant portion of growth in heat demand in Jilin has been met with new CHP units that are needed to supply heat but not electricity, which has further exacerbated wind curtailment. Shifting to consumption-based, cost-reflective tariffs for space heating could ease wind curtailment challenges by reducing demand for heat and creating business models for alternative (non-steam) technologies.

District heating reforms have been ongoing in Jilin and throughout China since the early 2000s. Heat pricing reform continues to be a priority for the Jilin provincial government.[67] Key challenges include tariff design, customer acceptance, and interagency coordination. Tariff design and customer acceptance challenges stem, in part, from the multi-unit characteristics of most conditioned buildings in Jilin. Heat transfer throughout buildings creates cost allocation challenges; a customer on the top floor, for instance, may have very low heat bills because they are "consuming" heat transferred from a customer on the bottom floor. Interagency coordination

[65] Optimal capacity expansion models can be used to develop resource portfolios and assess transmission capacity value. Production simulation models can be used to assess energy (congestion mitigation) value and flexibility (reduced wind and solar curtailment) value.
[66] Ideally, these regional spot markets would also have efficient congestion pricing.
[67] For instance, heat tariff reform was part of the Jilin government's 2016 *Implementation Guidelines on Promoting Price Mechanism Reform* (关于推进价格机制改革的实施意见).

challenges stem from the fragmented nature of policy and planning for district heating, which involves a mix of different provincial and municipal agencies and corporations.

In the near term, we recommend that Jilin develop a pilot for new heat tariffs and heat metering in new buildings, with different options for metering (e.g., building or individual apartment), thermostat control, and pricing (e.g., cost allocation factors, two-part prices) to gauge effectiveness, feasibility, and customer acceptance. As part of these efforts, we recommend exploring technologies and tariff options for non-steam heating options (e.g., electric heat pumps, electric hydronic heating, ground source heat pumps) in new buildings. This pilot could be in partnership with universities, for research purposes, and could ultimately be national in scope.

In the longer term, we recommend transitioning to consumption-based, cost-reflective heat tariffs for all customers, consistent with the Jilin government's goals. Nearer-term pilots can inform the longer-term transition to this goal.

Develop a long-term energy planning process to coordinate across different government agencies and sectors (Recommendation 7)

Historically, energy policy and regulation in both China and the United States has been siloed within different government agencies, according to a mix of end-uses and energy sources: electricity, industry, building heating, and transportation. As the energy sector becomes increasingly interconnected, the lack of a more coordinated approach to energy management has begun to affect the sector's overall economic and environmental performance.

In the United States, where states have significant jurisdiction over energy policy and regulation, growing interlinkages between traditionally siloed energy sectors are encouraging the development of statewide, multi-agency planning processes. These long-term planning processes provide a forum for different state agencies to create dialogue, develop a shared vision of the future, and coordinate policy.[68] For instance, in California the Energy Principals Group serves as a forum for the state's air quality, energy, and water resource agencies to regularly discuss strategies and interagency coordination for meeting California's long-term greenhouse gas (GHG) emission reduction goals. The Energy Principals Group's discussions are supported by quantitative analysis.

In Jilin, air quality, GHG emission reductions, and electricity-heat sector interactions are likely to be the principal drivers behind the need for greater interagency coordination. Meeting long-term air quality and GHG emission reduction goals will likely require a significant amount of fuel switching, as will also be the case in the United States.[69] We recommend that different Jilin agencies that are responsible for electricity, building energy, transportation energy, air quality, and water resources develop an interagency long-term planning process, such as through a working group. This process could help to: 1) develop a shared understanding of environmental goals, policies, and regulations, and 2) create consensus around technology pathways, costs and cost allocation, and strategies for interagency policy coordination.

[68] For an overview of state energy planning efforts, see http://www.naseo.org/stateenergyplans.
[69] See, for instance, California's 2017 "Scoping Plan" for meeting 2030 GHG goals, https://www.arb.ca.gov/cc/scopingplan/2030sp_pp_final.pdf; New York's 2015 State Energy Plan, https://energyplan.ny.gov/Plans/2015.aspx.

Appendix II-A: Economics of Wind-Powered Electric Boilers

The breakeven electricity price for electric boilers is the maximum electricity price (yuan/kWh) at which the boiler can recover its costs. This breakeven price is mainly a function of four factors:

1) the "wholesale" price at which the boiler can sell its heat output (yuan/GJ);
2) electric boiler costs (yuan/kW);
3) the efficiency of the boiler (%);[70] and
4) the annual operating hours (annual utilization) of the electric boiler.

At lower wholesale heat prices, higher boiler costs, lower efficiency, and lower annual operating hours, the electric boiler requires lower electricity prices to break even.

The below figure illustrates this relationship for different wholesale heat price and different operating hour assumptions, assuming a 95% efficient boiler with a cost of 170 yuan/kW.[71] For instance, at a heat price of 30 yuan/GJ and a utilization of 3,000 hours per year, an electric boiler would need an *average* electricity price of 0.09 yuan/kWh to break even. For an electric boiler that consumes 5% of its electricity on-peak at a price of 0.40 yuan/kWh, this implies an off-peak price of 0.08 yuan/kWh.

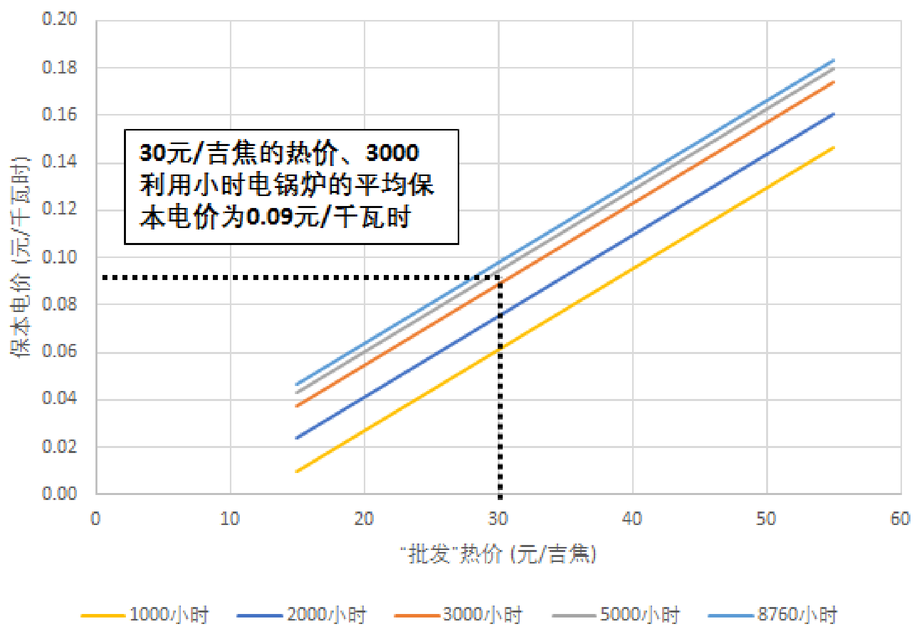

Figure 6. Illustration of relationship for wholesale heat price and operating hour assumptions

[70] This assumes that the only heating losses that must be recovered through the wholesale heating price are the boiler losses. If the boiler is also responsible for a portion of heating network losses (e.g., connection from facility to district heating network), the efficiency term would be lower, and the breakeven electricity price would be higher.
[71] The calculations below also assume financing of 5 years at 7% interest for the boilers, for an annual cost of 41 yuan/kW-yr.

This breakeven electricity price is far below current retail prices in China. Increasing wholesale heat prices and boiler utilization do not fundamentally change this outcome. A 95% efficient, 170 yuan/kW electric boiler operating 8,760 hours with a heat price of 40 yuan/GJ has a breakeven electricity price of 0.13 yuan/kWh. Reducing electric boiler costs would further increase this breakeven electricity price, but only marginally.

This conclusion highlights the fact that, at least in the near term, using electric boilers to centrally supply heat is likely to be cost-effective only for *balancing* wind energy. Balancing here refers to when wind energy is in surplus, relative to its minimum guaranteed or contracted hours, and its additional generation can be sold at very low prices. The low electricity prices needed for electric boilers to break even also implies a lower than average transmission prices, such as a non-firm price.

An alternative use for central-scale electric boilers could be as a replacement for standalone coal boilers, particularly in urban areas. However, the cost-effectiveness of using electric boilers to replace coal boilers should be evaluated against other potential options for improving air quality and replacing coal boilers.

Analytics of Breakeven Costs for Electric Boilers

The technical breakeven cost for a boiler operating on wind power is equal to

$$Net\ Income = Revenues - Costs$$

The boilers revenues are from heat energy sales, while its costs include the cost of the electric boiler, the costs of electricity, and operations and maintenance (O&M) costs

$$Heat\ Sales = Boiler\ Cost + Electricity\ Cost + O\&M\ Cost$$

The most straightforward way to calculate

Heat sales (yuan/kWh$_e$). For each kWh of electric heat input (= 3.6 MJ), heat sales are equal to heat output, net of efficiency losses, multiplied by a wholesale heat price (yuan/GJ)

$$Heat\ Sales = \frac{3.6\ \times\ (1 - Losses)\ \times\ Heat\ Price}{1{,}000\ MJ/GJ}$$

Boiler cost (yuan/kWh$_e$). Boiler cost is the unit cost of the boiler, in yuan/kW, multiplied by a capital recovery (annualization) factor and divided by the boilers annual operating hours

$$Boiler\ Cost = \frac{Unit\ Boiler\ Cost\ \times\ CRF}{Operating\ Hours} = \frac{Annual\ Unit\ Boiler\ Cost}{Operating\ Hours}$$

Electricity cost (yuan/kWh). On a per kWh basis, electricity cost (yuan/kWh) is the average price of electricity, calculated as a consumption-weighted average across different time-of-use price hours

$$Electricity\ Cost = Average\ Electricity\ Price$$

O&M cost (yuan/kWh). O&M costs are generally small relative to the cost of the boiler and are ignored here.

The breakeven average electricity price is thus

$$Breakeven\ Electricity\ Price = \frac{3.6\ \times\ (1 - Losses)\ \times\ Heat\ Price}{1{,}000} - \frac{Annual\ Unit\ Boiler\ Cost}{Operating\ Hours}$$

Appendix II-B: Danish Experiences in Using Electricity from Wind for District Heating

The Danish Government has set a target that more than half of the traditional electricity consumption[72] should be supplied by wind power in 2020. At the COP 23 in Bonn, the Danish government committed itself to remove coal completely from power generation by 2030. In the longer term, this wind expansion can be expected to increase even further as part of the Government's objective to be free of fossil fuels by 2050. The integration of wind power (and in recent years, solar power as well) has involved changes at all levels of the energy system, involving both technical measures and adaptions of energy markets support schemes, taxes, procurement of system services as well integration with the heat sectors.

Power system development and current status

Over the last 15 years, the annual Danish electricity consumption (including network losses) has been quite steady, at roughly 35 TWh per year, with the load varying between 2,100 MW and 6,200 MW. While demand may have remained largely unchanged, the power system in Denmark has however evolved from one consisting almost solely of large-scale thermal power plants, to a system comprised of a mix of large-scale units, small-scale units, auto-producers, and wind and solar units.

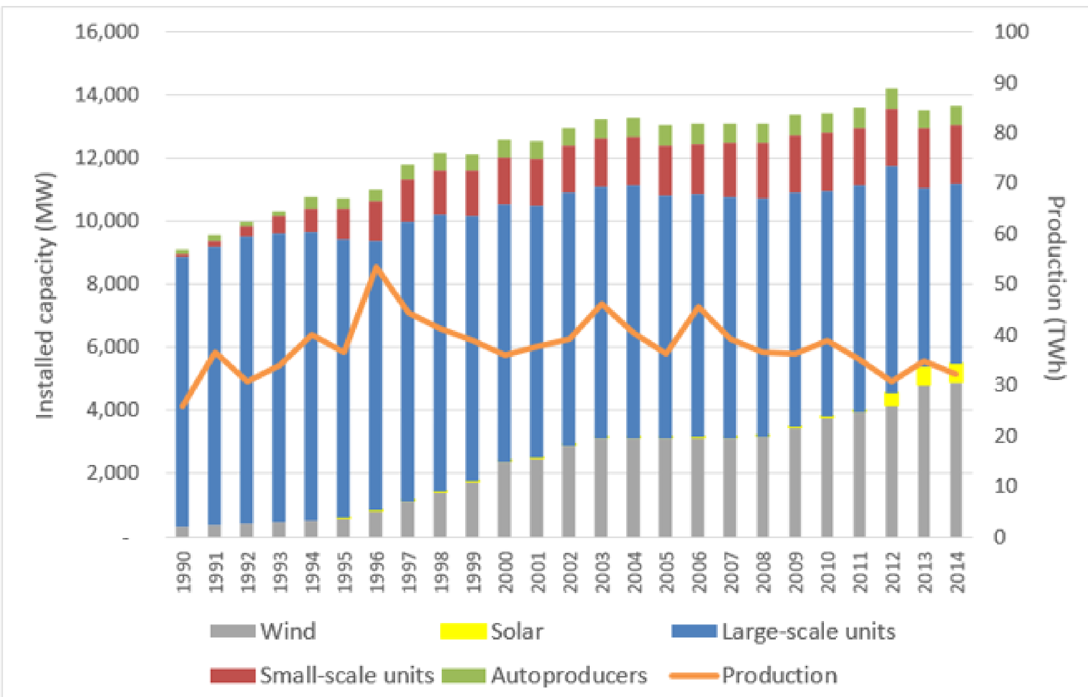

Figure 7. Development in installed power capacity in Denmark (left axis), and total production (right axis), 1990-2014

(Danish Energy Agency, 2015a)

[72] The traditional electricity consumption encompasses the kinds of electricity consumption that exist today, such as electricity use for lighting and household appliances. Non-traditional electricity consumption is the anticipated electricity consumption for heat pumps and electric vehicles, which will cause the total electricity demand to rise.

Figure 7 illustrates how the growth of wind capacity in Denmark over the last 25 years has largely come to replace capacity at large-scale power plants. In Denmark, all small-scale, and the overwhelming majority of large-scale, units are combined heat and power (CHP) plants. In terms of production, Figure 8 below highlights the fact that the last 6 years have seen wind (and more recently solar) greatly increase its share of Danish electricity production, largely at the expense of large centralized plants.

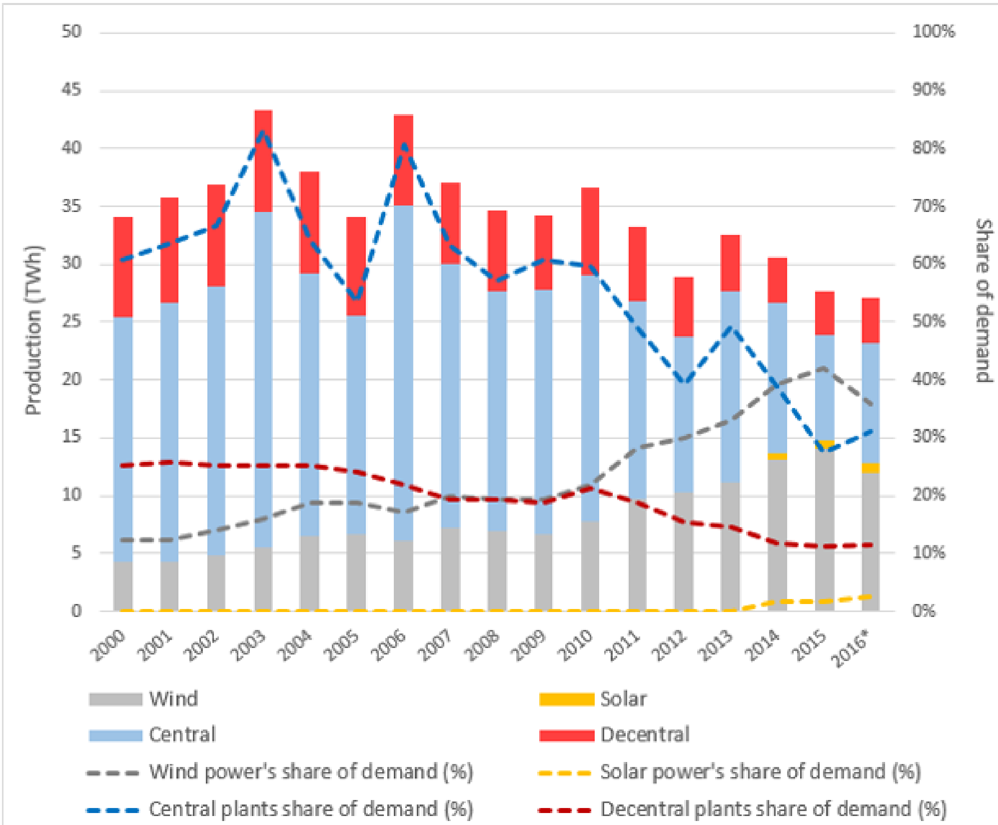

Figure 8. Danish annual electricity production according to production type (left axis), and share of annual demand (right axis)

2016 data was available through to the end of October, and was prorated, thus likely resulting in total wind production to be under estimated, and solar production overestimated. Note, 2015 was an abnormally good wind year (roughly 14% more energy in the wind than normal), while 2016 is an abnormally poor wind year (roughly 18% less energy in the wind relative to a normal year) (Energinet.dk, 2016a).

Figure 8 also clearly illustrates that in years with large electricity exports, such as 2003 and 2006, it is the large central power plants that provide this additional production.

As a result of the above described evolution, the Danish electricity system has in recent years distinguished itself internationally due to its ability to successfully integrate a growing percentage of wind and solar production. In 2015, wind and solar power accounted for 44% of national electricity demand (wind 42% & Solar 2%), and in numerous hours, a much higher percentage than this.[73] In total, here were over 440 hours (ca. 5.0% of the time) during which Danish electricity

[73] A larger portion of the wind power is located in the Western part of Denmark, where the share of wind power relative to electricity demand reached 55% in 2015 compared to 23% in Eastern Denmark.

production from wind and solar was greater than total electricity demand (for wind alone these figures were 400, and 4.6% respectively). If one instead focuses on hours when wind and solar accounted for more than 80% of electricity demand, for Denmark as a whole, in 2015 this occurred in nearly 15% of hours.

Challenges related to flexible RE integration

Generally speaking, due to the fluctuating and intermittent nature of wind and solar power production, there are three main challenges associated with their integration:

1. To ensure value when it is very windy and/or sunny (In a Chinese context, this would relate to reducing curtailment).
2. To ensure sufficient production capacity when there is no wind and/or sun. (I.e. wind and solar power expansion results in it being less attractive to build base load plants).
3. To balance wind and solar power production, i.e. managing wind and solar's fluctuating and partly unpredictable production patterns.

Ensuring RE electricity's value is crucial

If a large part of the produced wind and/or solar power electricity is sold at low or negative prices it reduces the incentive to invest in new wind and solar units. For this reason, it is crucial to ensure the value of wind and solar, both to maintain its socioeconomic value, and in order to preserve the economic foundation for continued intermittent RE power development. The solutions are to reduce production at other power production units, export to neighboring jurisdictions, or to increase electricity consumption where this is economically attractive. Existing and new electricity consumption (electricity for heat generation, electric vehicles, etc.) can also assist by not using electricity during periods of the day when the electricity system is most hard-pressed.

When these options have been exhausted it would be possible to curtail production from some of the wind and solar units, both for shorter periods consisting of a few minutes, or for longer periods extending several hours. This is possible for all modern wind and solar units. Excess electricity is therefore not a technical problem but rather an economic one, which can be minimized when the rest of the energy system is dynamic. In a future with a large share of wind and solar power, it will likely be economically beneficial to occasionally stop some wind and solar units.

Ensuring sufficient production capacity

The challenge of ensuring sufficient production capacity can be dealt with in several ways: establishing peak generation capacity such as gas turbines, or via a closer integration of grid with neighboring jurisdictions. Flexible electricity consumption and the activation of emergency power generators are also interesting possibilities that are, to a certain extent, already in use. The value of the various alternatives depends in particular upon the length of the duration that the strategy can be used. While certain types of flexible electricity consumption can only provide a solution for a number of hours with lacking capacity, other possibilities such as peak load plants or international grid connections can be used over longer periods of time with no wind power production, which potentially could last for a number of weeks.

Balancing wind power

There is a need for balancing if e.g. the production from wind and/or power falls unpredictably, either as a result of altered wind or solar conditions, or due to production issues caused by technical problems or damage to the production units. The latter also applies for outages of other production units or transmission connections. Balancing can be achieved either by power plants or by consumers being prepared to change their production/consumption patterns with relatively short notice (see the text box below). Gas turbines can be well suited to meet this need, but also coal-fired power plants and other productions units, electric boilers, or electrical heat pumps, and other consumption units can provide balancing services. Increased integration with neighboring countries' energy systems can also provide access to more sources capable of providing balancing.

Solutions to integration challenges

The key to integrating a growing proportion of intermittent renewables is improving the flexibility of the overall power system. In Denmark, this has largely involved a two-pronged approach:

a) Improving interconnector capacity & system stability tools
b) Providing actors incentive to become more flexible via price signals in the electricity and heating markets.
While the primary focus of this memo is on the latter, the Danish interconnector capacity will first be described briefly below.

Utilization of interconnectors

Danish interconnectors to Germany, and particularly to Norway and Sweden, are very efficient means of integrating wind power. In practice, the availability of interconnectors (primarily to Germany) can be limited to due to congestions in internal grids in Denmark's neighboring countries.

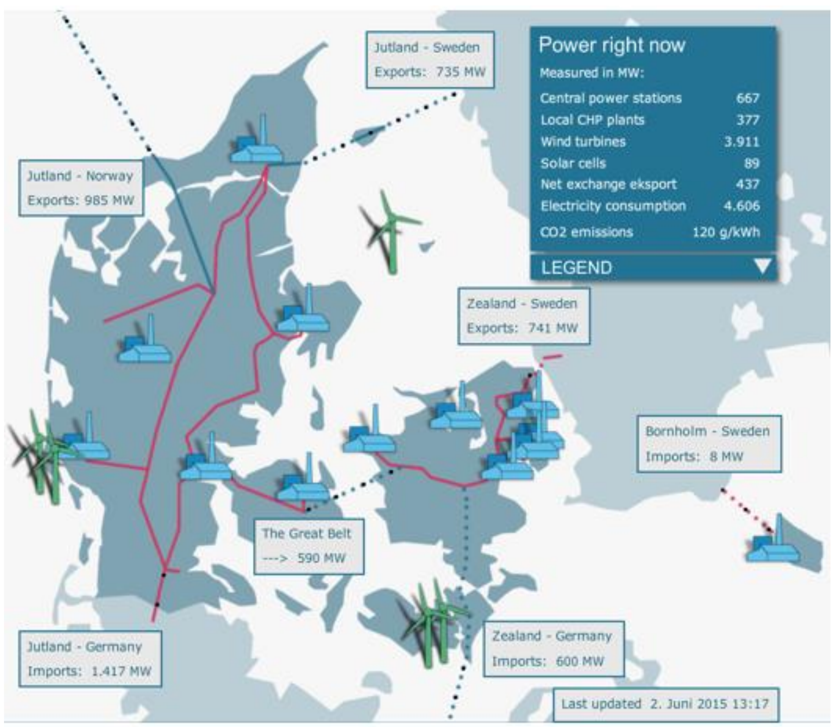

Figure 9. Snapshot of the Danish power system June 2nd 2015 at 13:17
The blue buildings represent central power stations, while wind turbines signify offshore wind farms. Red lines indicate an AC transmission line and blue lines indicate a DC transmission line (Energinet.dk, 2015a).

Figure 9 displays a snapshot of the current power system in Denmark for a day in June of 2015, including the use of interconnectors with Norway, Sweden and Germany. Currently, the total technical import/export capacity to Norway and Sweden are respectively 1,650/1,700 MW and 1,980/2,440 MW while the figures for Germany are 2,100/2,380 MW. Moreover, Eastern and Western Denmark are connected via a 600 MW DC connection. In addition, interconnectors are planned to the Netherlands (700 MW by 2019) and to the UK (1,400 MW by 2022). In addition, the Danish TSO (Energinet.dk) and the German TSO (TenneT) have agreed to upgrade the interconnection between Western Denmark and Germany to 2,500 MW in both directions. By 2022 Eastern Denmark and Germany will add 400 MW of indirect connected capacity via the Kriegers Flak project, which involves the establishment of two offshore wind parks, and an offshore grid connecting the two parks to one another and to Denmark and Germany. Lastly, a 770-kilometer subsea HVDC cable with 1400 MW of capacity is being developed to connect Denmark with the UK by 2022.

System stability tools

In hours where electricity production from wind is greater than electricity demand, it is not enough to merely have sufficient transmission capacity to export the excess electricity production to Denmark’s neighbors, but the security of the system must also be maintained. Energinet.dk recently experienced a day when none of the central power plants were producing electricity, but because Energinet.dk now has 7 synchronous condensers totaling roughly 2,100 MVar throughout the system at its disposal, the system security was maintained.

Flexibility using prices signals and the integration of heating and cooling in the energy system

Denmark has achieved a highly flexible power system and ability to integrate a high share of variable energy production from renewable energy sources though a consistent effort to integrate all parts of the energy system. Today the most important sources of flexibility come from the ability to vary production on central CHP plants and using thermal storages in district heating systems. In recent year’s distributed CHP plants have played an increasingly important role in securing balancing of the electric grid through the integration of the electricity and heating sector. In this integration, the high penetration of district heating plays a vital role in combination with the use of electrical heat pumps and electrical boilers. With the Danish plans to increase renewable energy production even further, balancing needs and flexibility in the energy system will be even more challenged in the future, increasing the need for integration of large scale heat pumps, district cooling, electrical boilers and new storage technologies.

<u>Successive markets allow for and incentivize increased flexibility</u>

To organize the Danish electricity markets, a series of markets have been established and electricity is now traded via the Nordic electricity exchange Nord Pool. The markets serve the needs for both planning and intraday intervention, as the Nord Pool market has been developed in parallel with the technical developments and interconnectors between countries. The Danish power market is divided into a day-ahead spot market and several regulating and ancillary power markets. The markets have been introduced gradually and function as illustrated in Figure 10 and comprise: Day-ahead spot market (2005), Regulating power market (2006), Automatic primary reserve market (2009).

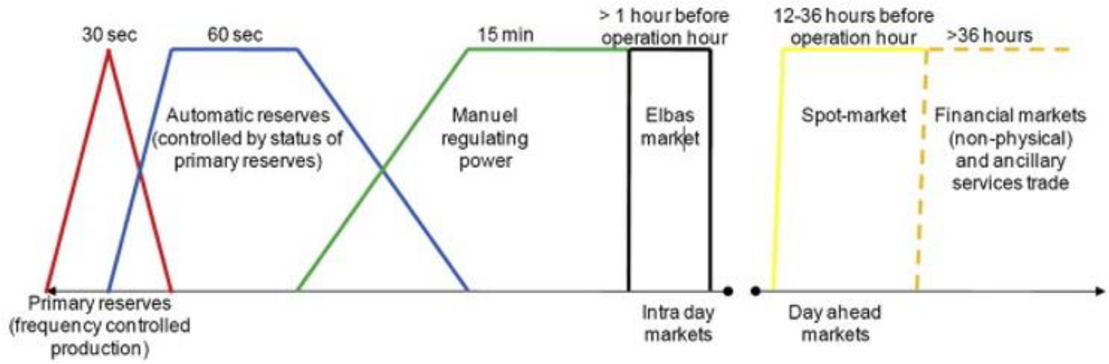

Figure 10. The main electricity markets in Denmark

(Sorknæs, Strøm, Tang, & Andersen, 2013)

<u>Flexible power plants</u>

As was outlined above, the high share of wind power that has developed in Denmark over the last 25 years has provided an early incentive for increasing the flexibility of thermal power plants. From the power plants' perspective, the high fluctuation of residual load resulting from the high share of variable wind power generation leads to steep load gradients. It also requires fast start-ups at low cost, and as low minimum stable generation as possible.

Figure 11 illustrates the challenge for thermal power plants resulting from increased fluctuations of residual load. In the case of a renewable power shortage (load exceeds RES-E generation), there is an increasing demand for steep positive load gradients on running plants, as well as a need for fast start-ups of hot, warm or cold thermal plants. Vice versa, steep negative load gradients on running plants and as low minimum stable generation as possible are required in case of a renewable power surplus. In between these two cases, rapid fluctuations of residual load require large positive/negative load gradients.

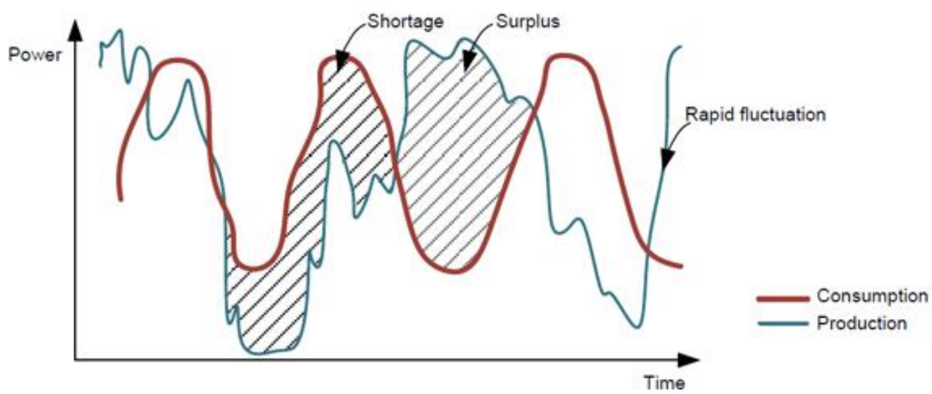

Figure 11 The flexibility challenge for thermal power plants due to fluctuating consumption and VRES-E production

(Blum & Christiansen, 2013)

Thus, Danish coal power plants that had originally been designed as base load units have been transformed into some of the most flexible power plants in the World. Today, load gradients of

$4\%P_N$/min for coal-fired units ($9\%P_N$/min for gas turbines) are considered the Danish standard. The minimum load could be decreased down to $10\%P_N$ and a fast start is possible within less than 1 hour.

Flexible power plants and the district heating system

From a power system perspective, the flexibility of CHP plants and in district heating systems play a very important tool for flexibility. The Danish district heating plants optimize their bidding into the power market to ensure lowest possible net-costs for the heat supply when taking power prices and possibilities for flexibility into account. The use of Storage, multiple production technologies for each grid, and a well-functioning market place with clear price signals, as well as the integration of heating and cooling loads are all important aspects. The accumulated flexibility of the system is illustrated in Figure 12 below.

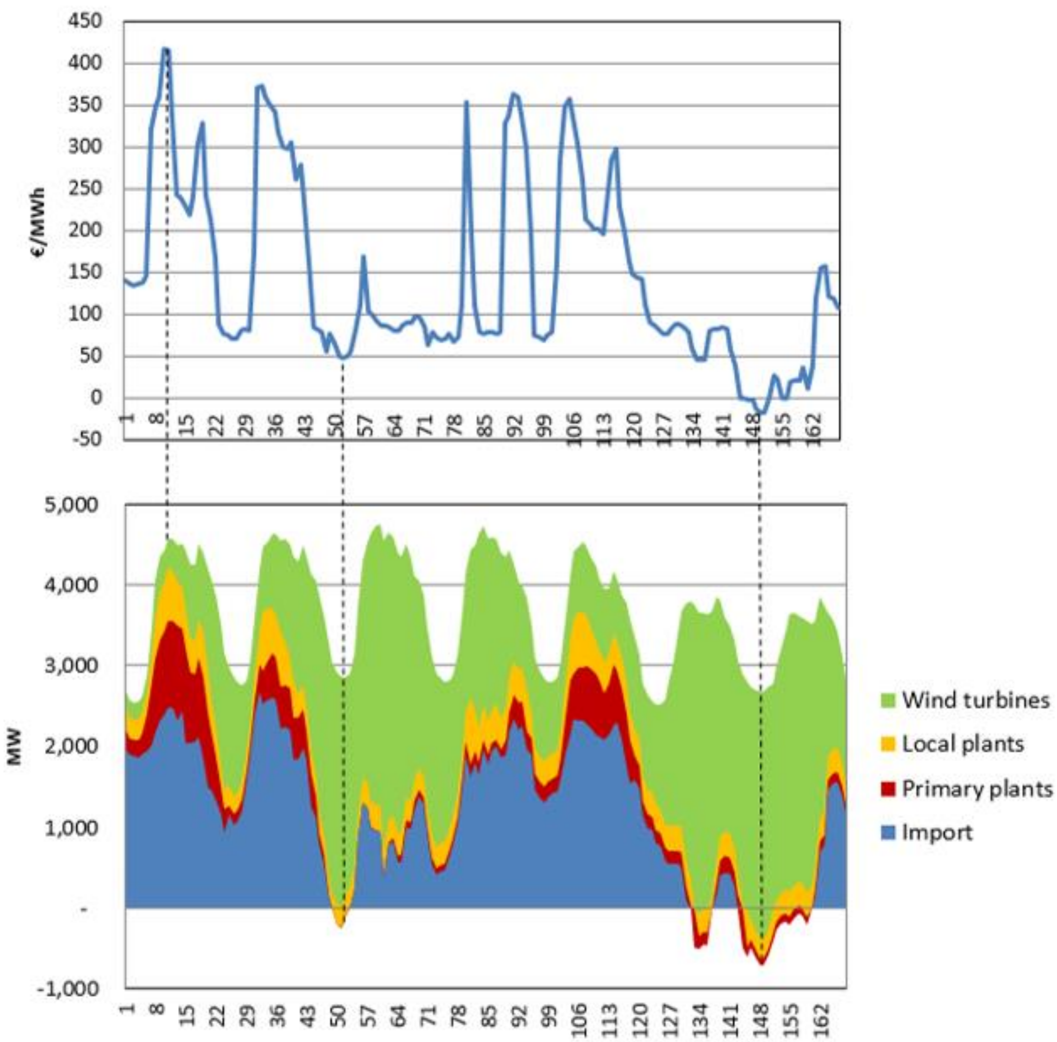

Figure 12. Hourly dispatch for the week of August 31st to September 6th, 2015, and linkage between spot prices and dispatch
(Energinet.dk, 2016b).

During the week depicted in the figure, large amounts of electricity were imported via the international connections when wind production was low (blue portion). In addition, production from the large primary plants (red) and smaller local plants (yellow) were also higher during these periods. Meanwhile, when wind production was very high, interconnectors were used to export (particularly when demand was also low in the weekend). In addition, both the large primary and smaller local plants also greatly reduced and/or shut down production during times with large amounts of wind.

Flexibility from a heating perspective

Most combined heat and power system features one or more large CHP units as well as Heat Only Boilers (HOB) for peak-load periods or back-up supply. Even though HOB's often does not have as high efficiencies as a CHP plant they are still an important part of offering flexibility to the overall system. Conventionally, converting electricity to equal amounts of heat is a bad idea, since thermal electricity generation is less efficient than heat generation. The possibility to commit a HOB unit, and consequently reduce electricity production and increase the demand can more than offset the loss of efficiency from a systems perspective and, when the opportunity cost of electricity is zero (wind is being curtailed) free electricity can be made into free heat with the possibility of efficient and cheap storage, compared to electric storage.

Heat storages are commonly large insulated tanks to store hot water. In contrast to electricity, heat is an energy form, which can be storage quite cheaply and for considerable periods of time, without significant losses. Moreover, the technology is cheap compared to electrical storage, both in terms of batteries and establishment of hydro storage. Heat storages can be used to decouple the time of heat generation on a CHP with the time of consumption. Therefore, when there is need for electricity, the CHP can generate and store heat more than simultaneous demand. When there is abundant wind power, the CHP can then also be able to curb production since heat can be supplied from the storage unit. Another type of flexibility provided using storage is the ability for CHP plants with extraction units to be able to increase flexibility without affecting heat deliveries.

The district heating and district cooling grids have with their large thermal storages for hot and cold water in combination with large heat pumps, compressor chillers and electric boilers (there exists roughly 300MW of electrical boilers in the DH grid). From a systems perspective, this gives the heating and cooling grids the possibility to impact the electricity system the same way a large battery would by soaking up electricity while the prices are low and avoid consumption when prices are high. Through the market based pricing system on electricity the need for storage

> Consider a CHP unit with the ability to generate 0.3 units of electricity and 0.6 units of heat per unit fuel input. Having a power generation efficiency of 30% and a heat generation of 60% gives the CHP a combined efficiency of 90%.
>
> The back-up boiler is an older vintage with a heat efficiency of 85%. Which unit should generate needed heat in a situation where there is an abundance of wind power from and overall efficiency perspective?
>
> Despite the CHP unit's higher overall efficiency, the opportunity value of the power is now zero. Electricity not generated by the CHP is made up by reducing curtailment.
>
> The same quantity of heat and power can be delivered with about 0.5 less units of fuel pr. unit of heat, leading to reduced fuel costs and emissions. The savings occur from the combined interest of the wind and district heating plant owners. Aligning these interests is the key institutional challenge.

capacity will in time be reflected in more fluctuating electricity prices. This should encourage investors to invest in demand side energy systems including district heating and cooling storages and heat pumps, as opposed to inflexible solutions.

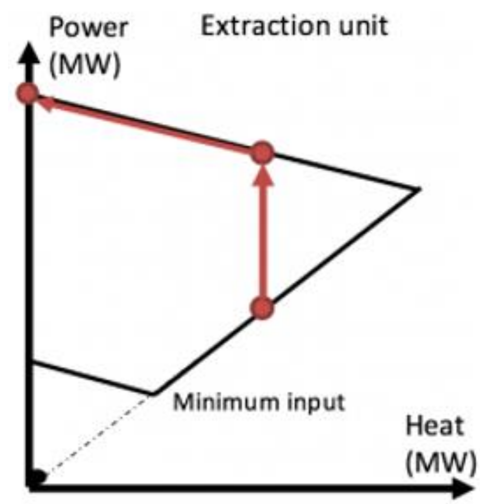

Figure 13. CHP extraction unit's production range

In balancing wind power, CHP extraction units can play another important role. Extraction steam turbine CHP's have considerable flexibility in the power-heat output combination (as illustrated in Figure 13. Due to the intermittent nature of wind and solar, power production is not perfectly predictable, and it can therefore be necessary to have reserves available for the unexpected drop-off in generation. One method enabled by the storage, is that it is possible to very quickly boost power output by discontinuing heat supply from the plant. This option can reduce the necessity of having other regulating units online. This is important since each thermal generator brought online in a power system, increases the combined minimum thermal power output and leaves less accommodation space for wind and other renewables. The increased flexibility provided through the storage and flexible operation of the CHP plant allows the heating companies to supply heat at the lowest possible cost by planning operations according to the lowest possible net-cost of heat generation (variable costs – minus electricity sales). For production planning purposes, the net cost of generation can be illustrated as a function of power price for each technology. Figure 14 displays a comparison of the heat production price from different units, depending on the electricity price.

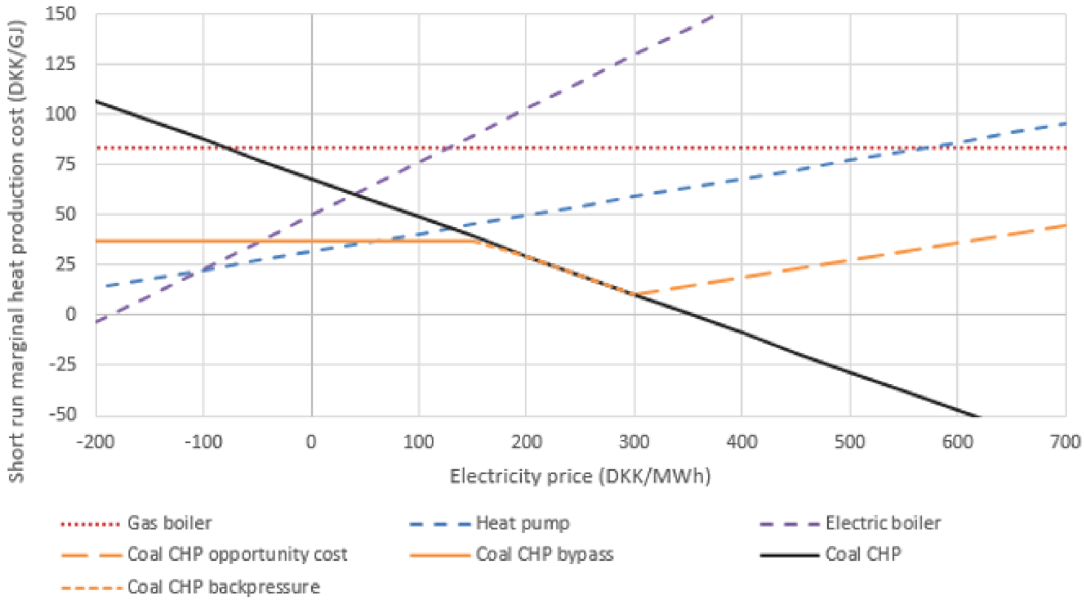

Figure 14. Short run marginal heat production price for different units depending on the electricity price

Illustrative example. Actual prices will depend on fuel prices, emission prices and taxes and subsidies.

At very low (negative) electricity prices, electric boilers offer the cheapest price, since the boiler can earn money by consuming electricity. As electricity prices rise, it can be cheaper to use first the more efficient heat pump, and then the turbine bypass on the CHP-plant. At prices above approximately 180 DKK/MWh, CHP-production is beneficial. If the CHP-plant is an extraction unit, with very high electricity prices, opportunity costs will occur, since the plant could choose to produce more electricity when omitting heat production thereby increasing income. As a result, at very high electricity prices, the gas boiler will therefor provide the cheapest option.

Example of a Danish distributed CHP plant

As an illustration of the role of distributed CHP in the flexibility of the energy system the smaller Skagen plant can serve as an example. It presents technical designs of a flexible energy system in distributed CHP solutions, which can both balance production and demand and fulfil voltage and frequency stability requirements of the grid. The following example illustrates how such operation has already been implemented in a number of plants for the last 5-6 years.

The simultaneous operation of the plant and the market is done in the following sequence: Bids are given a day ahead on the spot market. Bids for electricity production from the CHP units are given on the basis of alternative costs of supplying heat from the gas boiler or the electric boiler. In the calculation of the bids, the heat storage option is carefully considered. The CHP units can be operated in the regulating power market in the following two ways: If operation in the spot market is won, a downward regulation can be offered; if not, an upward regulation can be offered. The reverse situation applies for the electric boiler. Additionally, the CHP units can be operated in the automatic primary reserve market. This is done by bidding the CHP plants into the spot market at full capacity minus 10 percent. If the bid is won, the same unit can be offered for a plus/minus 10 percent operation in the primary automatic reserve market. The same principle can be applied to the electric boiler.

Unit	Size
CHP capacity	13 MW_e and 16 MJ/s (three 4.3 MW_e natural gas units)
Heat storage	250 MWh
Peak load boilers	37 MW
Electric boiler	10 MW
Compression heat pump	Under consideration

Figure 15. Overview of the Skagen CHP plant

(EMD, 2016)

A weekly production example of the operation of the plant could be seen from the actual production data in Figure 16. On that day, the three CHP units bid (and were selected to provide) their full load into the spot market during the hours with the highest prices in the middle of the day and in the evening. On Friday May 14th, the three CHP units were active in the spot market during the well-paid hours in the middle of the day – however not at full load – the remaining capacity was traded into the primary reserve market. On Sunday May 16th, the electric boiler was run half load – allowing it to be offered both as positive primary reserve (reducing electricity consumption), and as negative primary reserve (increasing electricity consumption). On Tuesday May 18th, all three CHP units were activated in the regulating power market for an upward regulation. The following day, the 10 MW electric boiler was activated in the regulating power market for a downward regulation.

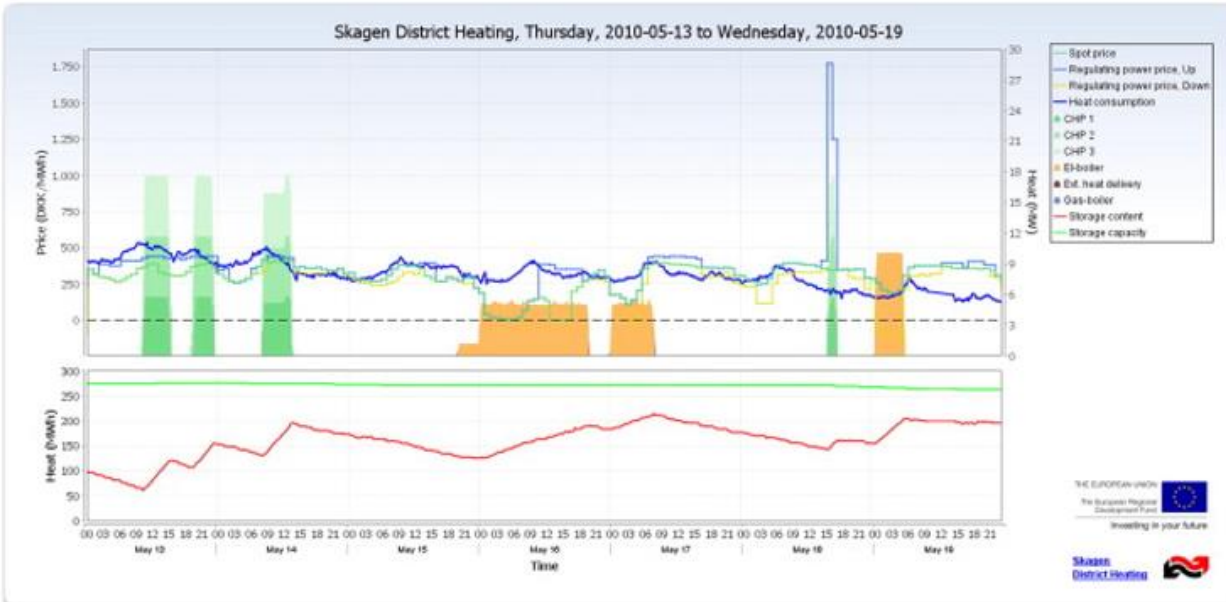

Figure 16. Weekly production from the Skagen CHP plant, May 2010

(EMD, 2016)

Another interesting example of Skagen CHP's regulating potential occurred on the 25th of March as illustrated in the daily operation in Figure 17. In the first four hours of the day, the plant was awarded negative primary reserve with the 10 MW electrical boiler. Hence, it operated below full capacity. A little before 3 AM, Skagen was selected to provide downward regulation in the regulating power market, so the electric boiler increased its output to approximately 4 MW. At the same time, the plant still performed the frequency regulation which it had been selected to provide in the primary reserve market.

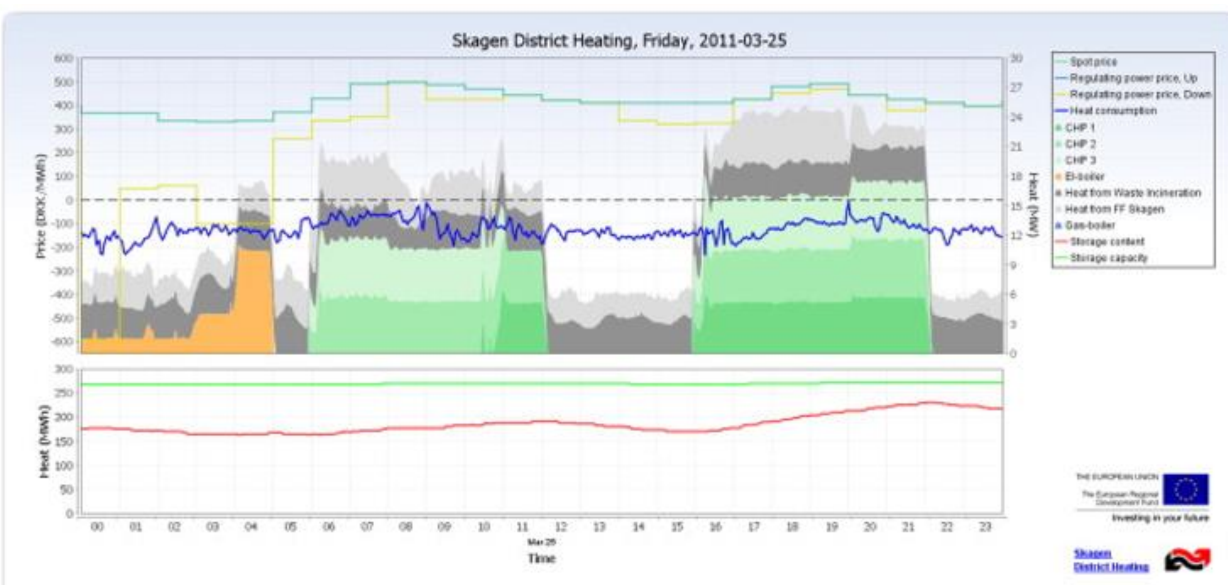

Figure 17. Weekly production from the Skagen CHP plant, March 2011

(EMD, 2016)

After 4 AM, Skagen had not won anymore primary reserve and the electric boiler was therefore offered at full capacity (i.e.10 MW) for downward regulation in the regulating power market, winning it for a full hour. From 16 to 20 PM, only part of the CHP units was sold in the spot market, which made it possible to offer both positive primary reserve and negative primary reserve during these 4 hours.

Lessons learned for heating sector

In summarizing the above into overall lessons learned, the successful Danish integration of wind integration via the heating sector can largely be attributed to two closely related elements:

1) The coordination and dispatch of heat generation from different sources depending on the overall system value.
2) Having systems in place that provide incentives to invest in flexibility on the heating side, thereby exposing heat producers to varying electricity prices.

The first of these elements relates to dispatching heat production based on the electricity price during a given time frame. As was highlighted in the examples above, having additional technologies (i.e. electric boilers, heat pumps, CHP, etc.) to select from allows for cost optimization depending on the electricity price. Introducing heat storages to this equation furthers this optimization by increasing the number of hours during which the most-cost effective technology can provide heat.

Being able to select from a variety of heating technologies at a given time necessitates that these technologies are present in the energy system, and this relates to the 2nd element. Investments in additional technologies and storages require that the proper incentives and frameworks are in place in order to drive investment. By exposing heat producers to varying electricity prices, as well as allowing them to participate in various ancillary services markets, Danish heat producers know that they can realize value via increased flexibility.

Main messages for China

Taking the general lessons learned, and putting them into a Chinese context, the main messages for China from the Danish experiences are (Bregnbæk, 2015):

- The Danish thermal power plants are all CHP units, but the district heating systems also have back-up from heat-only-boilers (HOB) and heat storages. Both increase the flexibility for the CHP plants. Furthermore, the power plants are typically extraction units which allow for a very flexible relationship between power and heat production. As such, from a technical stand point, Danish thermal power plants can operate flexibly and independent of the current need for heat supply if necessary.
- The Danish power market, an integrated part of the Nordic Power Market, has both a day-ahead market and an intraday market. In addition, the final adjustments between load and supply are carried out using a market for power reserves. This allows for a quick adaptation to changes in the wind power forecasting facilitated through dynamic price signals.
- The Danish CHP plant owners use the technical possibilities and the market set-up to ensure the lowest possible heat price, taking into account the income from power production. This means that the heat producers will choose between heat from the CHP plants if the power price is high enough, heat from heat storage of from HOB if the power price is low, or even choose to use electric boilers, if the power price is very low (or negative).

- The Danish mechanisms to avoid curtailment could be used successfully in China. The Chinese CHP plants are modern and could be operated flexibly; heat storages at the CHP plants are both feasible and low-cost solutions for decoupling the instant power and heat production, and with a proper power market design, the owners of the CHP plants could get strong incentives for flexibility and least-cost operation.
- Of course, such a system cannot be introduced overnight and transition schemes must be considered, including incentives to invest in increased flexibility and storage options.

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3. Enhancing Demand Response and Promoting Demand-Side Resources

Key Recommendations

The followings three recommendations are considered highest priority to develop a self-sustaining and robust demand response (DR) market in China.

1. Establish stable cost recovery and funding mechanisms to promote DR as a resource (Recommendation 5)
2. Maximize DR resource potential by tapping opportunities beyond peak load reduction (Recommendation 2)
3. Create roles and business opportunities for load aggregators to deliver greater DR potential (Recommendations 3)

Pilot Background

The objectives of Shanghai and Jiangsu Demand Response (DR) pilots are to address current demand side management (DSM) and DR challenges in order to develop long-term mechanisms to promote DR as a sustainable and cost-effective resource for reliable and flexible power system operation. The two pilots aim to develop a policy framework and market strategies to adopt and expand DR programs for industrial, commercial, and residential customers, and to explore reform of electricity markets to elicit greater value from these programs.

The U.S.-China cooperation aims at recommending viable options to address some key challenges to more widespread use of DR resources faced by the pilots (and China as a whole), in particular:

- Utilities' reluctance to compensate load reduction when they can curtail customer load for free under China's "Orderly Use of Electricity" load control program;
- Power over-supply due to overcapacity in China's power industry creating less demand for DR;
- Insufficient use of DR resources beyond peak load reduction;
- Limited use of dynamic pricing and effective incentives to drive customer response;
- Lack of stable and sufficient designated funding sources to support DR; and
- Lack of power markets or market mechanisms to compensate DR resources.

Addressing these myriad of issues requires multiple strategies, some of which may happen concurrently whereas other strategies may need to be deployed prior to others. This paper offers recommendations for China's DR pilots in the following three specific topic areas based on U.S. experience in creating a self-sustaining and robust DR market:

1) enhancing DR value;

2) sustaining and stimulating greater DR participation;

3) markets and policies for scaling DR development.

We recommend eight important actions under these three topic areas. Actions on the top of the list can be targeted first while those further down the list require more substantial changes to existing utility operational and power market structures.

1) *Integrate DR into power system dispatch procedures*
2) *Maximize DR potential by tapping opportunities beyond peak load reduction*
3) *Create roles and business opportunities for load aggregators to deliver greater DR potential*
4) *Promote more effective tariffs to increase customer response*
5) *Establish stable cost recovery and funding mechanisms to promote DR as a resource*
6) *Stimulate DR through more structured compensation incentives*
7) *Allow DR to be monetized through power markets*
8) *Pursue policy changes to effectively drive large-scale DR deployment*

While the United States has a lot of useful and applicable experience with DR, we recognize China is still in the early stages of taking advantage of this resource and is exploring broader changes across the power sector that should be considered in addition to the information and recommendations in this report.

Specific Recommendations

1. Enhancing DR Value

Integrate DR into power system dispatch procedures (Recommendation 1)

DR is a dispatchable resource that can provide system capacity, energy, and ancillary services. This complete range of value, however, has not been fully recognized in China's grid dispatch procedures. The previous rulemaking in the Demand-Side Management Administrative Measures did not focus on dispatching demand-side resources. The newly revised rulemaking issued jointly by China's six ministries requires for the first time that DR resources be included in the power system operation and dispatch to enhance the flexibility of grid operations.[74] While grid operators in China are revising operation procedures to include DR, the U.S. practices in directly integrating DR into dispatch instructions could provide useful insights for China. For example, each U.S. bulk power system operator (ISO/RTO) has some form of a reliability-based DR program and clear protocols in place for dispatching DR under certain operating conditions.[75]

We recommend grid operators in China formally integrate DR resources into their operations protocol and set forth clearly defined conditions under which capacity or emergency-based DR is dispatched to ensure DR is more efficiently utilized and its value is appropriately captured relative to the cost incurred to procure it. DR is not the only resource being treated inefficiently in dispatch procedures; rationalizing dispatch is a significant theme in both the Jilin and Guangdong pilot recommendations as well.

Maximize DR potential by tapping opportunities beyond peak load reduction (Recommendation 2)

[74] Demand-Side Management Administrative Measures (Revised Edition) http://www.ndrc.gov.cn/gzdt/201709/W020170926634283414217.pdf
[75] For example, see ISO-NE (2017) OP-14 - Technical Requirements for Generators, Demand Response, Asset Related Demands and Alternative Technology Regulation Resources. Operating Procedures. ISO New England. Effective January 17, 2017.

The current focus of DR programs in China's pilots has been primarily on event-based peak load reduction. This narrow focus has minimized the value for DR in China. DR could provide value-added services well beyond peak load reduction. Surveys of utilities indicate that utilities in the U.S. have developed "more flexible DR resources by adapting legacy load management and interruptible/curtailable DR programs to respond not only just to reliability concerns but also to reduce exposure to high market prices." [76] The 2015-2016 California Demand Response Potential Study estimates that DR could have the potential to provide 600 MW of regulation services and 350 MW of load following services cost-competitively in the California power system. [77] Table 2 summarizes various DR applications utilized in the United States.

Table 2. DR Applications in the U.S.[78]

Product产品		Physical Requirements具体要求			
Product Type 产品类型	General Description 整体描述	How fast to respond 多快做出响应	Length of response 响应时长	Time to fully respond 完全响应时间	How often called 响应频率
Regulation 功率调节	Response to random unscheduled deviations in scheduled net load 应对规划好的净负荷中随时出现的变化	30 seconds 30秒	Energy neutral in 15 minutes 15分钟	5 minutes 5分钟	Continuous within specified bid period 在特定拍卖期间连续
Flexibility 灵活度	Additional load following reserve for large un-forecasted wind/solar ramps 给无法预测的风光电做额外的负荷跟踪储备	5 minutes 5分钟	1 hour 一小时	20 minutes 20分钟	Continuous within specified bid period 在特定拍卖期间连续发生
Contingency 应急	Rapid and immediate response to a loss in supply 快速或瞬间对供给的缺乏作出反应	1 minute 1分钟	≤ 30 minutes 小于30分钟	≤ 10 minutes 小于十分钟	≤ Once per day 小于每天一次
Energy 电量	Shed or shift energy consumption over time 减少或转移负荷	5 minutes 5分钟	≥ 1 hour 大于1小时	10 minutes 十分钟	1-2 times per day with 4-8 hour notification 每天1-2次，4-8小时预先通知
Capacity 容量	Ability to serve as an alternative to generation 作为发电资源不足的替补	Top 20 hours coincident with balancing authority area system peak 与区域系统平衡运行机构的系统峰值相吻合的头20个小时			

With rapid growth of renewable energy, DR can play a significant role in integrating renewable energy to the power grid and reduce renewable curtailment. For example, the California Demand Response Potential Study estimates that by moving 10 -15 GWh per day of customer load to the middle of the day could effectively address the "duck curve" effect[79] and save approximately

[76] Cappers, P., Goldman, C. and Kathan, D. (2010) Demand response in US electricity markets: Empirical evidence. *Energy*. 35(4): 1526-1535
[77] Jennifer Potter and Andrew Satchwell, "Process for Developing and Conducting a Demand Response Potential Study," a presentation in Jiangsu, China, October 28, 2016
[78] Hummon, M., Palchal, D., Denholm, P., Jorgenson, J., Olsen, D., Kiliccote, S., Matson, N., Sohn, M., Rose, C., Dudley, J., Goli, S., Ma, O., 2013, Grid Integration of Aggregated Demand Response, Part 2: Modeling Demand Response in a Production Cost Model. NREL Technical Report, NREL/TP-6A20-58492. https://www.nrel.gov/docs/fy14osti/58492.pdf
[79] Duck curve refers to a situation that in locations where significant solar power production exists, power produced by sources other than solar and wind has to be increased rapidly right after the sunset to offset the loss of power generation from the solar systems, resulting in a steep ramping load curve that resembles the silhouette of a duck.

$450 million each year from curtailed renewable energy production.[80] In Arizona, the local utility, Arizona Public Service (APS), has recently launched a new "reverse demand response" program that provides incentives (e.g., negative pricing[81]) for residential customers to increase load in the middle of the day by installing "smart thermostats, electric vehicle charging infrastructure, energy storage and water heater timers" to absorb excess of solar power generation in real-time.[82]

In the near term, we suggest that DR pilots pursue DR valuation and potential studies to better understand diversified roles that DR can play in enhancing the reliability and flexibility of grid operations. Study results would assist China's DR pilots identify opportunities for DR to expand its current role. We also suggest grid operators, distribution utilities, and/or load aggregators to take full advantage of DR's ability to respond in real-time to imbalances on the grid and address the needs of flexibility, ramping, or even frequency regulation. Such real-time response however requires wide adoption of smart metering, signal communication, and load control technologies.

In the long term, China needs to develop the necessary institutional frameworks to support use of advanced DR-enabled technologies. To ensure the compatibility and interoperability of different DR technologies and devices, we recommend China strengthen its effort in developing open communication protocols and technology standards for achieving seamless communication and automation.

Create roles and business opportunities for DR aggregators to deliver greater DR potential (Recommendation 3)

DR aggregators are active in the two China DR pilots, including the deployment of load sensors and customer engagement, but have not developed a sustainable and profitable business model because they rely heavily on end-use customer energy use advisory services rather than coordinating customer loads to provide high-value services to meet the needs of distribution companies and grid operators. This narrow business focus has limited aggregators' opportunities to generate more revenue.

In the United States, utilities have increasingly outsourced DR services to third-party aggregators on a pay-for-performance basis.[83] Such a move could be attributed to the need of utilities for meeting demand-side reduction goals set forth by state utility regulators.[84] U.S. electric utilities and DR aggregators developed DR business models over the past two decades based on explicit

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[80] Jennifer Potter and Andrew Satchwell, "Process for Developing and Conducting a Demand Response Potential Study," a presentation in Jiangsu, China, October 28, 2016

[81] Rather than charging customers for consuming power in the time-periods when renewable power generation will be curtailed, utilities pay customers for consuming the power, creating negative pricing.

[82] http://www.utilitydive.com/news/arizona-utility-will-use-reverse-demand-response-to-avoid-renewables-curt/505943/

[83] At PG&E, for example, on a MW basis, aggregators deliver roughly 40% of DR reduction while 60% coming from programs administered by the utility. The ratio is to shift closer to 50-50 over the next few years (interview with a PG&E DR program manager).

[84] Cappers, P., Goldman, C. and Kathan, D. 2010. Demand response in US electricity markets: Empirical evidence. *Energy*. 35(4): 1526-1535

roles and responsibilities for the administration and acquisition of DR resources.[85] Such experiences may offer insights for catalyzing DR business opportunities in China.

Most U.S. DR aggregator business opportunities come from either enrolling customers into ISO/RTO or utility DR programs, or acting as the program administrator responsible for implementing utility DR programs (e.g., some investor-owned utilities' demand bidding programs shown in Appendix B). DR aggregators are able to pool DR resources across a large number of customers and coordinate these resources in a way that ensures a specified level of energy and/or capacity is always available to a utility or grid operator. In providing DR services to utilities (at the retail level) or grid operators (at the wholesale level), DR aggregators have a contractual obligation to deliver a certain amount of capacity if dispatched. They are also responsible for all roles from customer acquisition, marketing, sales, retention, support, and event notification to customer resource dispatch, settlement, and compensation payments. Customers authorize the aggregators to act on their behalf with respect to all aspects of DR services offered to utilities and grid operators thereby passing on the risk of non-performance to the aggregators. This has resulted in greater success for aggregators when enrolling customers, than direct utility efforts that fully expose customers to non-performance risk.

Aggregators can also provide "benefits stacking" services that create bundled offerings in DR, energy efficiency, distributed generation, and/or energy storage to create multiple value streams that could allow them to earn more revenue while benefiting utilities and customers.[86]

We recommend DR pilots explore new business models aimed at creating more business opportunities for aggregators to capture greater DR potential. In the near term, we recommend China's DR pilots considering the following:

1) Leverage the large amount of customer power use data collected by load aggregators to understand customer load types and their response characteristics. This helps aggregators determine dispatchable load and load that has fast response capability, assisting them in identifying business opportunities by managing those loads to meet grid conditions;
2) Encourage DR aggregators to create more diversified service offerings and extend services beyond customer energy efficiency advisory services to bundling DR and energy efficiency and coordinating customer response to DR signals to better serve the needs of power systems. DR aggregators could best use the opening up of the competitive retail market to team up with electricity retailers to expand the customer base for bundled DR and energy efficiency services. As the role of DR aggregator expands, regulators and system operators should continue to examine power system needs holistically to maximize the benefits of DR without causing unintended reductions in the control and coordination of the transmission system or distribution system.

In the longer term, we recommend China's DR pilots consider the following:

1) DR aggregators' business models could be expanded to aggregate electric vehicles, behind-the-meter storage, and distributed generation;
2) With higher penetrations of renewable energy in China's grid, aggregators' use of fast response DR to provide ancillary service support will become increasingly important;

[85] Cappers, P. and A. Satchwell. 2015. "Considerations for State Regulators and Policymakers in a Post-FERC Order 745 World." LBNL Report 6977E.

[86] http://www.brattle.com/system/news/pdfs/000/001/302/original/Stacked_Benefits_-_Final_Report.pdf?1505227794

3) Develop automated load response (autoDR) infrastructure and DR Management System (DRMS) to improve DR efficiency and minimize performance risk. Developing automation is particularly important for fast DR which requires seamless operations.
4) Regulators need to decide what opportunities exist for different types of resources to provide value and how they can extract that value. Then, regulators need to determine who is eligible to bring them forward to the market and how that entity can be compensated for doing so. The more consistent the approach is to bringing different resources to market, the easier it will be for aggregators to capture economies of scale by bringing multiple resources from a single customer forward.

2. Sustaining and Stimulating Greater DR Participation

Promote more effective tariffs to increase customer response (Recommendation 4)

While the Jiangsu Pilot has implemented a summer critical peaking price (CPP) for a limited number of large industrial customers, its modest price increase of less than 10% over the existing time-of-use (TOU) on-peak rate has not sent a strong pricing signal to encourage end-users to reduce their electricity use during the critical peaks. To some extent, Jiangsu's CPP is more a mechanism of collecting charges to incentivize load reduction by other customers and less a rate strategy to discourage customers to use power during critical peaks. In the United States, the most effective time-based tariff programs have been developed with very strong price signals (500% above the existing rate) to encourage peak demand responsiveness to system conditions.[87] In addition, to enhance the effectiveness of DR program design, consumer behavior studies have been carried out by unities with the support of U.S. Department of Energy, to assess customer acceptance, retention, and response to time-based rates in order to improve DR program designs and implementation strategies.[88]

We offer several recommendations to expand DR through retail tariffs. These are also mentioned in Recommendations #1 and #7 for the Jilin and Guangdong pilots respectively.

In the near term, we recommend four incremental steps that China could take:
1) As China is cautious on changing retail prices, especially for residential and small commercial customers, it may make sense to keep the initial focus on industrial and large commercial customers in reforming retail tariffs to make them more flexible to grid conditions;
2) Create event-based critical peak price (CPP) and set it at substantially higher rate than regular on-peak Time-of-Use prices to better reflect power system conditions during a critical peak.
    - CPP could be adopted on either an opt-in or opt-out basis. The two enrollment approaches could yield different results.[89]

[87] Faruqui, A. and Palmer, J. (2012) The Discovery of Price Responsiveness - A Survey of Experiments Involving Dynamic Pricing of Electricity. Social Sciences Research Network.
[88] For an evaluation of DOE's CBS, see: Cappers, P. and R. Scheer. American Recovery and Reinvestment Act of 2009: Final Report on Customer Acceptance, Retention, and Response to Time-based Rates from Consumer Behavior Studies." November 2016. LBNL-1007279
[89] Cappers, P. and R. Scheer. American Recovery and Reinvestment Act of 2009: Final Report on Customer Acceptance, Retention, and Response to Time-based Rates from Consumer Behavior Studies." November 2016. LBNL-1007279

- Explore a capacity reservation (CRC) type of charge to fund DR. As described in Appendix III-A, some U.S. utilities have adopted a CRC as a fixed monthly charge payable by customers in advance for reserving a certain amount of load exempt from the high price of electricity during a critical peak pricing event. The reserve payment could allow the revenue to be used to compensate other DR participating customers that reduce their load.

3) Given change of price is sensitive in China, provide customers price protection, as a temporary (12 months or less) measure to ease transition onto a new tariff, or rate discounts, especially for vulnerable populations who are adversely affected by volatile bills, when exposed to high-priced events[90].
4) Gradually expand TOU pricing over time to more customer groups, like residential and small commercial customers, which are only on a volumetric use based tiered price structure without time-varying tariffs. To minimize the potential pricing impacts on small customers, TOU pricing for residential and small commercial customers could initially be explored on a voluntary opt-in basis.

In the longer term, we recommend more significant changes to retail tariffs:

1) Design more dynamic Time-of-Use tariff structure with greater seasonal and hourly differentiation to foster demand elasticity. For example, China could adopt more dynamic pricing schemes such as variable peak pricing that defines TOU periods in advance but keeps the price for the on-peak period adjustable according to power system and power market conditions.[91] This helps more closely link retail prices and wholesale spot market prices;

2) With the rise of distributed energy systems that have the potential to disrupt the existing utility business model, utilities in China should consider working with regulators to work with regulators to assess the feasibility of developing a retail tariff design that would adapt to this change. One option could be a "full value" retail tariff design that prices customer loads and compensates distributed generation at the grid's 'full value', while simultaneously recovering the costs of the grid fairly. According to a recent report, this could "more accurately compensate customer and third-party contributions to managing the grid, collect the utility embedded costs equitably and efficiently, increase competition for distributed services, [and] lower customer costs through more efficient use of the distribution system."[92]

Establish stable cost recovery and funding mechanisms to promote DR as a resource (Recommendation 5)

Allowing distribution utilities to include prudent expenses related to demand-side management (DSM) in the costs of supplying electricity has been included in both the 2010 Demand-Side

[90] For more information about U.S. vulnerable population's experience with CPP see: Cappers, P., Spurlock, C. A., Todd, A. and Ling, J. (2016) Experiences of Vulnerable Residential Customer Subpopulations with Critical Peak Pricing. Lawrence Berkeley National Laboratory, Berkeley, CA. September 2016. LBNL-1006294.

[91] For an example of this type of rate design and the U.S. experience, see: Oklahoma Gas and Electric (2011) OG&E Smart Study TOGETHER Impact Results. https://www.smartgrid.gov/sites/default/files/doc/files/GEP%20OGE%20Summer%202010%20Report%20Final-copyright%20corrected.pdf

[92] For a detailed discussion on full value tariff, please see http://www.ethree.com/wp-content/uploads/2016/12/Full-Value-Tariff-Design-and-Retail-Rate-Choices.pdf.

Management Administrative Measures and its newly revised edition in China. However, this policy has not been fully adopted by distribution utilities as there are no detailed guides from NDRC on how this would be implemented. As such, effective cost recovery mechanisms have not been established in China allowing utilities to aggressively pursue DR by recovering the costs, including administrative costs, equipment costs, and customer incentives.

In the United States, energy efficiency (EE) and DR cost recovery mechanisms have been implemented in 46 states[93] to allow the utility fully recover all expenses related to delivering EE and DR programs. Under such mechanisms, program costs are usually recovered from all customers through retail rates or as an explicit surcharge, often called a systems benefit charge (SBC), recognizing that all customers benefit from EE/DR programs and should, therefore, pay for them. EE/DR program budgets are calculated by the utility, but state utility regulators ensure costs are prudent and programs are cost-effective because the funding is from ratepayers. Because EE and DR program costs are recovered via energy bills rather than from state budgets (i.e., via taxpayers), funding levels have remained stable over the past several years despite cuts in public spending in many U.S. states since the financial crisis of 2008. Cost recovery mechanisms have often been implemented in conjunction with shareholder incentives for achieving bigger saving targets and lost revenue recovery mechanisms (e.g., revenue decoupling).

We offer several recommendations for China to establish DR cost recovery and funding mechanisms for DR. In the near term, we recommend the following prioritized actions:

1) Provide specific central government guidelines directing distribution utilities on how to include demand-side costs in their allowed cost of providing reliable electricity services. It is important to ensure that DR investments included in the cost basis are deemed to be cost effective, as demonstrated by a process to determine whether the total resource benefits of the DR programs exceed the total resource costs. In the United States, utilities generally may not recover costs for investments in DR programs that are not deemed cost-effective because the funding is from ratepayers and must be spent in their best interest.

2) Further evaluate and improve Jiangsu's approach of charging the largest industrial customers (315 KV and above) a modest CPP price (less than 10% overlaid onto the TOU peak rate) during specific peak events and utilizing the revenues to compensate residential and commercial customers who curtail their power usage during the critical peaks. Jiangsu's approach adheres to a concept of a fairness, because the party that benefits from continuing to consume electricity (i.e., the industrial users) pays the other party (the residential and commercial users) that sacrifices by reducing power usage during peak electricity shortage. The approach, however, has resulted in inadequate funding for DR because the price spread between the special peak price and regular on-peak rate is nominal and only a small number of industrial customers are subject to this special price.

   This approach may be optimized as follows to create more stable funding:
   - Increasing the number of participants subject to a special price; and
   - Instead of a direct government intervention in compensating residential customers from the charges on industrial customers as Jiangsu pilots does through its CPP program,

[93] Institute for Electric Innovation [IEI] (2014). "State Electric Efficiency Regulatory Frameworks." IEI Report, December.

explore a market-driven compensation scheme that enables customers to trade their reduced load to those customers that need to keep their load.

3) In the longer term, we recommend:

- Leverage the T&D pricing reform in China to allow utilities to recover cost-effective investments in distributed energy resources (DERs), including DR, in their T&D cost base. To incentivize utilities to increase investment in DER, we recommend that NDRC put forward targets to mandate DER deployment (more details in Specific Recommendation 8);
- Explore effective business opportunities that could generate steady revenue streams (more details in Specific Recommendation 3);
- Monetize DR through competitive power market systems (more details in Specific Recommendation 7);
- Consider creation of ratepayer-supported funding mechanism for DR through a tariff add-on.
    - China's newly revised Demand-Side Management Administrative Measures calls for local governments to create designated DSM fund from differentiated pricing and government budget. This is certainly a desirable move towards creating funding for DR. However, relying on government budget and differentiated pricing that is applicable only to limited number of industries, China will still face insufficient fund to roll-out large-scale DR programs.
    - Surcharges applicable to all ratepayers helps create stable and consistent funding levels that support a robust DR market. Tapping into the ratepayer funding follows the principle that all users of power benefit from DR that helps to reduce building costly peaker units and/or using fuels at prohibitively high price, while improving overall system efficiency.

Stimulate DR through structured compensation incentives (Recommendation 6)

DR pilots in China have created compensation incentives to award customers for their DR participation. However, these programs have only provided limited opportunities for customers. Relevant U.S. experience offers some insights on setting compensation incentives to 1) elicit effective responses and 2) assure predictability of the response.

Eliciting Effective Responses

Compensation-based DR programs were created in the United States to give customers incentives that are separate from, or additional to, their retail electricity rates. Normally, these programs can be categorized into two types: 1) voluntary reduction, and 2) mandatory reduction. In the former, customers voluntarily reduce their power use on a periodic basis in exchange for compensation that helps reduce their overall electricity costs. No penalties are imposed for non-response. In the latter, customers make pledges to reduce load whenever they are called upon and generally receive a reservation payment that is fixed on a monthly, seasonal or annual basis regardless of whether or not DR events are called. Utilities in the United States activate this option when the grid is approaching its limits. Instead of cutting customers off, utilities declare a grid emergency, and if customers respond by decreasing their power usage during the event period then load drops. In addition to the reservation payment, customers who respond to the call during an event also typically receive compensation for their performance. In order to determine the value of load reduction and thus payments to DR participants, utilities or grid operators either use a multi-year average market clearing price in the capacity markets, or base compensation on the avoided costs of providing the same functional service through employing traditional supply-side resources. Appendix III-B describes some compensation-based programs carried out in the United States.

In the United States, different arguments exist regarding the advantages and disadvantages of the tariff-based vs. the compensation-based DR programs. Some industry stakeholders argue compensation-based programs, especially those requiring mandatory reductions, elicit more reliable response because the risk of penalties for non-response is more motivating than the opportunity to save money in time-based tariff programs. Some other market observers, however, critique the baseline method used for measuring peak-time reductions in the compensation programs. They also point out the potential issue that incentive compensation can compromise fairness since some customers who receive incentives are free riders and incentives could also reward random variations in consumption.[94]

It is important for China to assess these potential issues and determine the effectiveness of different options when it weighs tariff-based vs. compensation-based DR programs. Customers should not necessarily receive compensation if tariff-based programs effectively trigger customer response as desired. Such payments may otherwise result in a subsidy when customers already are on a dynamic retail rate and subsidies lead to inefficient market outcomes. However, changing tariff structures may take more effort in China and DR pilots may need to rely now on compensation mechanisms to increase customer participation in DR.

Assuring Predictability of Response

To become a viable alternative to supply-side solutions, DR has to perform at a predictable level of resource guarantee to be comparable with supply-side options. Under China's existing DR pilots, however, customers are neither under an obligation to deliver DR load changes nor penalized for their failure to meet the obligation. The lack of performance assurance could make it hard for DR to effectively compete with traditional supply options. It is important to level the playing field between supply- and demand-side options, one component of which may be to assure that compensation schemes are linked with effective penalty systems to enhance performance, especially if such performance is used to meet resource adequacy requirements and/or supply-demand balance.

In the United States, voluntary load reduction programs do not impose penalties, while mandatory reduction programs have penalties for non-delivery or under-delivery of a committed DR resource. Comparing the two options, there is a lack of certainty on performance under voluntary options while response is predictable under the mandatory option. DR programs for capacity planning in the United States have established performance assurance systems through which non- and under-performance would be penalized if response were mandatory when scheduled. For examples, under the Day-Ahead Demand Response Program of New York-ISO, a penalty is assessed when DR resources selected in the Day-Ahead market to provide energy fail to provide scheduled load reduction in real time. The penalized amount is set for the greater of

[94]For a discussion on some potential issues with compensation-based DR, see: https://www.greentechmedia.com/articles/read/Peak-Time-Rebates-Money-for-Nothing

buy-through at Day-Ahead or Real-Time marginal price. To ensure the penalty is legally enforced, compliance rules and penalties are incorporated into settlement mechanisms.[95] Penalty for non-compliance can be substantial, which would not only eliminate the capacity revenue of DR providers but also become a charge for them since utilities or system operators have to pay much higher spot prices to other providers that can fill the undelivered resources.[96] Overall, the U.S. experience with DR has shown that program design elements such as compensation level, performance penalties, and aggregation requirements for small loads are significant factors affecting the predictability of DR.[97]

We offer several recommendations for DR pilots to develop more effective compensation schemes. In the near term, we recommend:

1) Create a more flexible voluntary load reduction compensation programs such as demand bidding and scheduled reduction as described in Appendix B to better accommodate customer needs.
2) Create opportunities for customers to receive fixed payments for making advance commitments to load reduction. When obligations are made ahead of DR events, response is predictable.
    - DR pilots in China should pay attention to the tradeoffs between compensation options set on an energy basis (i.e., Yuan/kWh) vs. a capacity basis (i.e., Yuan/kW-month).
    - Paying on an energy basis could create revenue uncertainty for DR providers – because if there is a year when there are no or few DR events, they will receive little payment.
    - By contrast, using the reservation basis as described in Appendix B would generate more stable revenue, but may lead utilities to overpay DR providers if utilities' estimate of price or quantity is wrong.
3) Replace universal compensation strategy with more effective options that offer different levels of compensation based on factors such as length of advanced notification, number of called events, and locations of system congestion. The ComEd's Smart Usage Program is a good example of employing distinguishable compensations (see Appendix B).
4) Establish a proper DR performance assurance system that helps position DR as a trusted resource. Such assurance system should set up necessary compliance rules with effective penalties in place.
    - Penalties are an important part of the assurance system, though not necessary under all situations. U.S. experience shows that penalties are more appropriate for DR in addressing resource adequacy and capacity planning, when the system operator pays in advance to ensure future resource availability, in lieu of investing in supply-side resources.

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[95]For DR programs implemented by New York-ISO including its' Day-Ahead Demand Response Program, see: http://www.nyiso.com/public/webdocs/markets_operations/services/market_training/workshops_courses/Training_Course_Materials/NYMOC_MT_ALL_201/Demand_Response.pdf

[96] Borgatti, M. "Comparison of Performance-Based Capacity Models in ISO-NE and PJM," http://www.pjm.com/~/media/committees-groups/task-forces/urmstf/20160602/20160602-item-09-pay-for-performance-and-capacity-performance-comparison.ashx

[97] Cappers, P., Goldman, C. and Kathan, D. 2010. Demand response in US electricity markets: Empirical evidence. *Energy*. 35(4): 1526-1535

- Penalties may be less important or unnecessary in an energy market (once developed), depending upon the DR program structure, the purpose of the program, and the performance incentives that are in place.

In the longer term, we recommend establishing a more effective scheme that combines stimulating tariffs and effective compensations to offset the unfavorable impacts of stand-alone compensation programs discussed earlier in this section. Relying on multiple options rather than a single option can enhance DR's role as a reliable energy resource of balancing supply and demand since using compensation options in conjunction with more effective retail rates could help improve customer response.

3. Markets and Policies for Scaling DR Development

Allow DR to be monetized through power markets (Recommendation 7)

In China's DR pilots, it seems that neither power markets nor market mechanisms currently exist to allow DR to be monetized and scaled. It is, therefore, important for these pilots to develop viable market structures and adopt effective market mechanisms to expand DR through power markets. The United States has established the following market structures to enable participation of DR resources and monetization of DR services: (1) entering into a bilateral agreement between DR service providers and utilities, (2) participating through a specific demand response auction mechanism outside of a wholesale market, and/or (3) bidding DR resources into competitive regional "ISO/RTO" wholesale markets (in the parts of the country where they exist).

Bilateral Agreements

Historically, it has been bilateral arrangements between the largest end-use customers and the utility via interruptible or curtailable tariff rates. More recently, agreements of offering DR services are made bilaterally between load aggregators and vertically integrated utilities in traditionally regulated environments, and with distribution network operators located within a deregulated market structure.[98]

Auction Mechanisms

This mechanism, like the California Demand Response Auction Mechanism (DRAM) program enables utilities to procure the targeted level of DR resources to address the supply-demand imbalance and/or meet resource adequacy need. The strength of these auctions lies in the standard product definitions and contract language that simplifies the solicitation process.[99] As bidders gain experience with the process and become accustomed to market activities, average

[98] Cappers, P. and Satchwell, A. (2015) Considerations for State Regulators and Policymakers in a Post-FERC Order 745 World. Lawrence Berkeley National Laboratory, Berkeley, CA. February 2015. LBNL-6977E.

[99] Auctions differ from competitive solicitations and Request for Proposals (RFPs) in several ways and the specifics would depend on the particular design of the auction mechanism (e.g., forward or reverse auction), as well as the solicitation/RFP approach. At the most basic level, auctions, with sufficient competition, result in a price close or at marginal cost as the price is set after several rounds of bidding by suppliers. Solicitation/RFP processes typically require suppliers to guess at the most competitive price and only have one opportunity to make an offer. In that sense, auctions are a better approximation of a competitive market and may offer more transparent price-setting than solicitations/RFPs.

prices have fallen in these auctions. Nonetheless, care must be taken in structuring the auctions to avoid bidders' utilizing 'bid to win' strategies that yield pricing too low to cover costs.

It is noticeable that California DRAM program has also created opportunities for integrating DR with other demand-side resources. For example, under California's program, participating DR resources are required to provide a significant length of load reduction – i.e., by making committed resources available four hours per day for up to three consecutive days, during specific hours of the day when utilities need it. DER, from behind-the-meter solar power and battery storage to smart thermostats and electric-vehicle at homes, can be included in the DR auctions as long as they can be aggregated at scale. Compared with traditional DR that requires providing the customer with advanced notification and waiting for them to respond and given the fact that there is reluctance on the part of customers to be called on many times, the storage-based DR resources have the potential to provide improved performance because these resources have the ability to fulfill its DR obligation with less disruption to the customers as they can draw power directly from storage. Beyond speed and reliability of response, storage-based DR can also be called on often, an attribute that is superior to traditional DR that must rely on customers' willingness. Despite these merits, however, it is important to realize that storage still faces tremendous technical and financial limits that prevent it from reaching its full potential.

Participating in Wholesale Power Markets

In the United States, there are a number of existing and emerging ways for DR to participate in ISOs/RTOs and this varies across the country, depending on the design of each ISO/RTO. For example, this may involve participating in capacity markets, energy markets, or ancillary service markets. These opportunities have had an important influence on the DR growth in the United States. It is important to understand that much of the DR in wholesale markets in the United States is compensated through a capacity payment in the capacity market and DR participation in the energy market and ancillary market is quite limited. This may not be the case in China at the current stage as there is no obvious need for China to create a capacity market due to the overcapacity of power supply. However, the situation may change when China is aggressively promoting electrification particularly in its industrial and transportation sectors.

Our recommendations for the Guangdong and Jilin pilots provide insights on how to build a functional power market in China. Here, we would like to offer specific recommendations to help China and its DR pilots develop viable market mechanisms to enable DR. In the near term, we recommend:

1) Encourage distribution utilities to procure DR through bilateral agreements with DR aggregators. Power market pilots such as the one in Guangdong facilitate annual bilateral contracts, focusing only on coal-fired power. Utilities and load aggregators could reach bilateral DR contracts and get them cleared through the centralized power trading systems, which could help streamline transactions;
2) Provide utilities with options to acquire DR resources through a DR auction. Absent a well-functioning wholesale power markets in China, an auction could serve as an initial step in enabling utilities to procure DR at a competitive price that might be lower than those reached in bilaterally negotiated contracts. Careful structuring of the auction will be required to mitigate low bids not anchored in true costs that may arise out of bidding strategies to win.

Some longer term recommendations for monetizing DR through market structures in China include the following:

Allow DR to participate in well-designed and functioning competitive wholesale markets. Well-designed competitive power markets will provide a level playing field for demand-side options to become viable resources that can compete cost-effectively with supply-side options. This should include market participation opportunities for DR to provide ancillary services such as spinning and non-spinning reserves and regulation (see also Recommendation #6 for the Guangdong pilot).

- The newly released Work Plan for Improving the Compensation (Market) Mechanism for Ancillary Services[100] encourages the active participation of third-party service providers and demand-side resources and energy storage in providing ancillary services. It is important for China to implement the new policy by developing programs that adopt DR perhaps in a stacked way with other resources such as DER and natural gas.
- With appropriate investment in automation, DR can provide these services with little impact on the customer's use of energy, comfort or convenience due to the short duration of response.
- Ancillary services require rapid response and generation-grade telemetry, thus limiting the pool of potential participants. Despite its challenge for DR to participate in ancillary services markets, the reward is more significant with much higher compensation as demonstrated in the United States;

Pursue policy changes to effectively drive large-scale DR deployment (Recommendation 8)

China will benefit by establishing a regulatory framework that sets priorities for utilities to acquire least cost demand-side resources before investing in supply-side options. This will work if DR is enabled to become a viable grid resource for balancing supply and demand.

The United States has established its federal and state regulatory frameworks for DR over the last three decades. U.S. and state policies have implemented various mechanisms to enable demand-side solutions, culminating in the establishment of DR as a resource to make the power markets operate more efficiently. Federal policy-makers and regulators took a series of legislative and regulatory actions to remove unnecessary barriers to and provide a level playing field for DR resources to compete with traditional generation in the wholesale market.[101] Furthermore, federal rulemaking mandates that local and regional transmission planning processes must consider transmission needs driven by public policy requirements, created opportunities for renewable energy and demand reduction strategies such as DR since development of these resources are part of the federal and state energy policies. In addition, state regulators have instituted policies that create positive earnings opportunities for utilities who achieve enrollment or load response goals.

At the state level, state policy-makers and regulators have developed various policy mechanisms that serve as an enabler for demand-side solutions including DR. These mechanisms include:

- **Integrated resource planning** (IRP) requires planners to consider a range of resource alternatives for long-term planning efforts including generation capacity (e.g., thermal, renewable, etc.), transmission and distribution capacity, and energy. At least 27 states

[100] http://zfxxgk.nea.gov.cn/auto92/201711/t20171122_3058.htm
[101] Cappers, P. and Satchwell, A. (2015) Considerations for State Regulators and Policymakers in a Post-FERC Order 745 World. Lawrence Berkeley National Laboratory, Berkeley, CA. February 2015. LBNL-6977E.

have established IRP rules or passed legislation requiring utilities to submit IRPs inclusive of demand-side resources.[102]

- **Loading orders** that places energy efficiency and demand response as the utilities' highest-priority procurement resource before any other options.
- **Non-wires alternatives** that have been considered in U.S. utility planning processes and regulatory requirements and reflect a shift for utilities from the traditional approach of relying upon new construction to a less capital intensive and more flexible approach with preferred solutions like distributed generation, energy storage, grid control devices/software, and demand response to meet changing T&D needs.
- **Energy efficiency resource standards** that set a minimum amount of energy savings and/or peak demand reduction targets for utilities within a targeted time frame.
- **Performance incentive mechanisms** that are designed to promote utility achievement of enrollment or load response goals
- **Regulatory treatment of utility investment** that allows utilities to accumulate costs associated with their DR investments as prudent regulatory assets and to later include the costs in their rate case. The regulatory treatment of utility investment can also allow utilities to recover additional costs associated with the lost revenue due to the DSM measures through a lost revenue adjustment mechanism.
- **Decoupling mechanisms** that are designed to remove any disincentive to demand-side solutions, by eliminating the link between electricity sales and utility profits.

Greater details on these enabling policies adopted at the federal and state level in the United States are provided in Appendix III-C.

The New York Reforming the Energy Vision (REV) is an effort at the state level that aims to create policy innovation that moves utility regulation beyond a cost-of-service system to more performance-based regulatory metrics that set utility returns based on distribution system efficiencies and end-use customer satisfaction.[103]

Some near-term recommendations for enhancing China's regulatory framework for DR include the following:

1) Develop a detailed plan with specific measures on how to meet the goal of using DR as a flexible peaking adjustment capability to achieve 3% of maximum load, as set forth in China's *Opinion on the Implementation of Orderly Liberation of Power Generation and Consumption Planning (关于有序放开发用电计划的实施意见);*
2) Enhance efforts in standardizing equipment, communication, and operational requirements related to DR to enhance DR inter-operability and remove technical barriers to facilitating greater deployment of DR;
3) Focus on DR related measurement & verification (M&V), which is critical to developing a robust DR market.

Some long-term recommendations for the central and provincial governments to consider in building a DR regulatory framework are as follows:

[102] Wilson, R. and Biewald, B. (2013) Best Practices in Electric Utility Integrated Resource Planning. Synapse Energy Economics. Prepared for Regulatory Assistance Project. June 2013.
[103] See https://rev.ny.gov/

1) Change utilities supply-focused investment mode by tracking more frequently occurring, record-breaking summer peaks to assess utilities' performance in effectively managing system peak and by providing a positive financial incentive to utilities for pursuing DR, as a way to compensate for the lost-earnings opportunities from load reduction.
2) Central and provincial governments could consider establishing demand-side resources portfolio standards (DSRPS) that set specific targets for adoption of distributed energy resources including DR.
   - Target-setting helps create consistent demand and drive the market for DER, but caution should be taken against setting targets arbitrarily.
   - Targets could be set up in several formats: 1) require local utilities to achieve percentage reduction of peak load as compared to a business-as-usual case, or 2) specify cumulative reductions by a certain period or establish annual reduction targets;
3) Consider DER resources in generation and transmission planning and integrated DR and power storage investments into the distribution system planning as a non-wires alternative to supply-side investments.
   - China's new *Electric Power Planning Administrative Measures* issued by the National Energy Administration in June 2016 provides a very useful blueprint for a new power sector planning process in China in promoting coordination of transmission and generation investments and planning, integration of national and provincial planning efforts, and better links between power sector and environmental planning,[104]
   - However, the new planning guidance does not incorporate demand-side resources in China's power sector planning process. Power sector planning should play an essential role in assessing cost-effective alternatives, including non-wire alternatives, and coordinating generation and transmission investments along with demand-side resource investments.
   - China's newly revised *Demand-Side Management Administrative Measures* calls for relevant government authorities to include DSM resources in national and local electricity development planning to ensure these resources are prioritized. Better alignment can be created between these two policies on planning as it relates to demand-side resources.

[104] For an analysis of the new policy, please see http://www.raponline.org/excess-coal-generation-capacity-and-renewables-curtailment-in-china-getting-with-the-plan/

Appendix III-A: Time-varying retail rate designs in the U.S.

Programs	Description	Examples
Super-peak price	The super-peak pricing is in effect in afternoon hours on summer weekdays with rates being significantly higher than those the rest of the day and on non-summer days	Arizona Public Service Company's super-peak price is 90% higher than its on-summer peak price 3-6 pm weekdays during June-August.[105]
Critical peak price (CPP)	CPP is a more dynamic form of time-of-use price. It is event-based and in effect only when utilities anticipate high wholesale market prices or power systems experience emergency conditions. Utilities may call critical peaking events during a specified time period and the electricity price during these events is substantially high. Participating customers are often offered a discount on their regular summer electricity rates in exchange for a higher price on a small number of CPP event days during the year.	Pacific Gas & Electric's Peak Day Pricing allows customers to receive discount from May 1 to October 31 in exchange for a higher price of $0.60/kWh added on top of on-peak rate between 2-6pm during 9 to 15 critical peaking event days in these months.[106]
Capacity Reservation	Capacity Reservation is another option that allows customers to self-select a specific amount of capacity (in kW) that they want to be exempted from the high price of electricity during a CPP event. They pay for this exemption through a fixed monthly Capacity Reservation Charge. During a CPP event, power usage protected under the customer's capacity reservation will not be subject to the CPP while usage during a	The San Diego Gas & Electric offers customers two options. One is CPP with a Capacity Reservation option. Another is the Alternate Rate Option for customers who choose not to participate in the CPP program and instead pay an alternate rate that also contains variable TOU rates that are higher than the TOU rates under CPP. [107]

[105] Levin, R. and Torres, E., "Can Arizona's Success with Time-of-Use Rates Be Replicated in California?" Center for Research in Regulated Industries 2014 Western Conference, Monterey, CA, June 9, 2014. http://www.dawg.info/sites/default/files/meetings/CRRI%20paper%20Levin-Torres%20June9%20final.pdf
[106]https://www.pge.com/en_US/business/rate-plans/rate-plans/peak-day-pricing/peak-day-pricing.page
[107] https://www.sdge.com/sites/default/files/documents/cpp_factsheet.pdf

Programs	Description	Examples
	CPP event that is not reserved will be billed at the CPP.	
Variable Peak Pricing (VPP)	VPP is a hybrid of time-of-use and real-time pricing where the TOU periods are defined in advance but the price established for the on-peak period varies by power system and power market conditions. It is different from TOU rates under which both the periods and rates for each period are pre-determined and fixed.	OG&E's SmartHours is a variable peak pricing program in which customers pay a variable rate during peak hours of 2pm-7pm every weekday from June 1 to September 30. Customers receive notice of the next day's peak price in advance. SmartTemp which is a programmable thermostat is used by many customers to better manage electricity use with variable peak prices. The smart thermostat allows customers to set their temperature-price preferences, which responds to the price signals from the utility based on the customer's pre-set preferences.[108]
Real-Time Pricing	Real-time pricing reflects the retail rate customers are charged for the electricity they consume on an hourly basis based on the corresponding hourly wholesale market price. To participate in a real-time pricing program, customers must have a smart meter installed that is capable of recording hourly power usage.	Under ComEd's residential Hourly Pricing Program, prices are based on the Residual ComEd Zone PJM wholesale market prices that vary from hour to hour and day to day according to the actual power market price. Customers receive an alert from ComEd when the real-time market price of electricity is high or are expected to be high so they can respond in real-time.[109]

[108] https://www.oge.com/wps/portal/oge/save-energy/smarthours/faq/
[109] For details about ComEd's residential Hourly Pricing Program, please see https://hourlypricing.comed.com/

Appendix III-B: Compensation-based programs in the United States

Programs		Description	Examples
Critical peak rebates (voluntary reduction)		During critical events, the price for electricity remains the same but the customer receives rebate at a single, predetermined value for reduction in consumption relative to what the utility deemed the customer was expected to consume.	Pepco's Peak Energy Savings Credit is a default compensation program that offers residential customers credits off their bill for reducing electricity use during Peak Savings Days called from May through September. Participating customers receive $1.25/KWh in the form of bill credit for reducing use below baseline on Peak Savings Days. Enrollment is not required and customers can participate in any particular Peak Savings Day. They will receive notification via phone call, text message, or emails the day before an event with specific hours to respond. No penalty if customers decide to not participate.[110]
Demand Bidding and scheduled reduction (voluntary reduction)		Customers either offer bids or select preferred reduction periods to voluntarily lowering energy use during specific periods. Customers receive compensation payment or bill credits for actual load reduction. No penalties for not reducing power. However, customers will not receive payment or credit if	Southern California Edison's Demand Bidding Program (DBP) is a year-round, flexible, Internet-based bidding program that offers business customers bill credits for voluntarily reducing power use when a DBP event is called. Participating customers are eligible for credits for reductions from 50% to 200% of their bid amount. [111] Under the Pacific Gas & Electric's Scheduled Load

[110] For Pepco's Peak Energy Saving Credit Program, see: http://www.pepco.com/my-home/save-money-and-conserve-energy/efficiency-rebates-and-incentives-and-programs/md-customers/frequently-asked-questions/
[111] For South California Edison's DBP, see: https://www.sce.com/NR/sc3/tm2/pdf/ce185_2007.pdf

Programs		Description	Examples
		power is not reduced during an event. Customers are incentivized to shift their load, but there is no guarantee of performance under voluntary options	Reduction Program, customers can select specific time periods in advance during summer peak time. The program pays customers $0.10/kWh per month for their actual load reduction. To receive the incentive, customers simply reduce their load by the committed load reduction during the selected time periods on selected weekdays.[112]
Reservation Payment Option (mandatory reduction)		Utilities offer monthly fixed payments to participating customers based on the amount of reduction pledged by the customer plus additional payments for the customer' actual load reduction. Monthly payments will be offered regardless whether DR events are called or not. Penalty is imposed for non- or under-delivery of DR. With customers' commitments in advance, response is predictable.	ConEdison's Smart Usage Awards allows customers to enroll in either 21-hour notifications or 2-hour notifications. Customers are paid $18-$25/kW per month for 2-hour notification and $6-$18/kW per month for 21-hour notification. DR capacity payments are also location based. For example, under the 21-hour notification option, DR capacity in Staten Island and Westchester is paid at $6/kW/Month while DR capacity in Brooklyn, Bronx, Manhattan, and Queens is paid at $18/kW/Month. If there are more than 5 events called in a given network, the Reservation Payment goes up by $5/kW per month. In addition, customers receive $1/KWh pay-for-

[112] For Pacific Gas & Electric's Scheduled Load Reduction Program, see: https://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-SLRP.pdf

Programs		Description	Examples
			performance compensation for actual reductions.[113]

[113] For ComEd's Smart Usage Awards, see: https://www.coned.com/en/save-money/rebates-incentives-tax-credits/rebates-incentives-tax-credits-for-commercial-industrial-buildings-customers/smart-usage-rewards

Appendix III-C: Regulatory Policies to Enable DR in the U.S.

Over the past three decades, U.S. state and Federal regulators and policymakers have adopted numerous policies for promoting and scaling DR. This section provides some details in developing regulatory policies to enable DR at the federal and state level in the United States.

Enabling Policies at the Federal level

There are a series of legislative and regulatory actions at the Federal level in the United States that aim at reducing the regulatory, institutional and market barriers to power sector reform in general and DR development in particular. The Table 3 below summarizes relevant legislation and regulations.

Table 3. Summaries of Federal Legislation and Regulations

Legislation or Regulations	Year Issued/Enacted	What for?
Energy Policy Act of 1992	1992	Started the process of deregulating the U.S. electric industry and opened the door for independent power producers to participate in wholesale power markets
FERC Order 888	1996	Mandates open and fair access to power transmission systems
FERC Order 2000	1999	Led to the formation of Independent System Operators (ISOs) that are responsible for operating regional wholesale markets
Energy Policy Act of 2005 (EPAct 2005)	2005	Further codified that a key objective of U.S. national energy policy was to remove unnecessary barriers to participation of DR resource in energy, capacity, and ancillary services markets by end-use customers and/or load aggregators at either the retail or wholesale level
FERC Order 890	2007	Enabled establishment of "an open, transparent, and coordinated transmission planning process."[114] Together with FERC Orders 888 and 2000, these regulations have helped open transmission access to a broader range of market participants.
FERC Order 719	2008	Opened up the opportunities for the participation of demand response in wholesale markets. The Order specially permitted load aggregators to bid DR on behalf of retail customers directly into organized markets, unless the relevant laws of

[114] https://www.ferc.gov/whats-new/comm-meet/2007/021507/e-1.pdf

		the local electric retail regulatory authority prohibit such activity
FERC Order 745	2011	Requires that demand response providers be compensated for reducing electricity load at the Locational Marginal Price, or the wholesale market price for energy, the same rate for generation resources
FERC Order 1000	2011	Requires that "[l]ocal and regional transmission planning processes must consider transmission needs driven by public policy requirements established by state or federal laws or regulations. Each public utility transmission provider must establish procedures to identify transmission needs driven by public policy requirements and evaluate proposed solutions to those transmission needs. Public utility transmission providers in each pair of neighboring transmission planning regions must coordinate to determine if there are more efficient or cost-effective solutions to their mutual transmission needs."[115] The regulation will have great impacts for renewable energy and demand reduction strategies as development of these resources are part of the federal and State energy policies.
FERC proposed rule to open up wholesale markets to energy storage and distributed energy resource aggregations	November 2016	If adopted will allow energy storage and distributed energy resource aggregations to participate in organized power markets, tearing down barriers to the participation of these resources in wholesale markets as they are technically capable[116]

Perhaps the most significant event related to DR is that the FERC Order 745 was challenged soon after its issuance in courts by a group of generators claiming that this FERC Order violated the exclusive right of states to regulate retail power markets. The U.S. Supreme Court ruled in January 2016 that FERC acted within its powers under the Federal Power Act (FPA) to regulate the wholesale market even when the FERC rule-making has indirect consequences on retail market conditions. The Supreme Court decision has great significance in creating legal certainty

[115] https://www.ferc.gov/industries/electric/indus-act/trans-plan.asp
[116]http://www.kilpatricktownsend.com/~/media/LEGAL%20ALERTFERC%20Proposes%20Rule%20to%20Open%20Up%20Wholesale%20Markets%20to%20Energy%20Storage%20and%20Distributed%20Energy%20Resource%20Aggregations12202016.ashx and https://www.ferc.gov/media/news-releases/2016/2016-4/11-17-16-E-1.asp.

for DR, which will bring a lot of trust to the market on demand response.[117] In addition to the simulative effect for DR growth, the Supreme Court ruling validating FERC's jurisdiction over DR could potentially open up opportunities for FERC to develop policies promoting a range of distributed energy services, such as distributed generation, rooftop solar PV, and battery storage. Although it is unclear how FERC will actually rule in the future, FERC's recent proposed ruling on energy storage and distributed energy resource aggregations in the wholesale markets could establish a path for how FERC may act given this new jurisdictional landscape.

Enabling Policies at the State Level

Loading Orders and Similar Regulations

In pursuing its future sustainable energy, the State of California has developed the Energy Action Plan established a "loading order" as governmental proclamations that define the priority order in which resources are to be developed. The California loading order places energy efficiency and demand response as the state's highest-priority procurement resource and sets aggressive long-term goals for developing these resources. Renewable energy/distributed generation and traditional generation are considered as the second and third priorities, respectively in the loading order, and only be considered once all energy efficiency and demand response resources are exhausted.[118] In addition, the State Government requires implementation of energy efficiency and demand response as a key strategy to meet the California's greenhouse gas emission reduction targets specified by AB32, a comprehensive policy to create enabling regulatory mechanisms to combat global warming.

In Massachusetts' Green Communities Act enacted in 2008, the legislation requires the state's utilities to procure all available energy efficiency resources that have cost lower than traditional energy sources do. Among the major provisions is a requirement for utilities to invest in energy savings and load reduction when they are less expensive than buying power. The law enable the state to see a surge in investing in energy efficiency and demand response, helping it achieving the state goal of reducing its use of fossil fuels in buildings by 10% and overall greenhouse gas emissions by 20% in the year 2020.[119]

Energy Efficiency Resource Standards and Peak Demand Mandates

In many states in the U.S., an Energy Efficiency Resource Standard (EERS) – also called Energy Efficiency Portfolio Standards (EEPS) – has been adopted as a policy tool to help create energy savings, cut peak demand, lower energy costs, reduce air pollution, and abate climate change. EERS, similar to the concept of renewable portfolio standards (RPS) which mandates utilities generate a certain percentage of electricity from renewable sources, requires either through legislation or administrative orders electricity and/or natural gas utilities to achieve specified levels of customer energy savings within a targeted time frame. An EERS does not mandate specific efficiency measures, but rather sets minimum amount of savings targets and allows utilities to choose how to best achieve those goals.

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[117] http://www.utilitydive.com/news/what-the-supreme-court-decision-on-ferc-order-745-means-for-demand-response/413092/

[118] http://www.energy.ca.gov/2005publications/CEC-400-2005-043/CEC-400-2005-043.PDF

[119] http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/analysis_group_gca_study.pdf

EERS can set up a target in several formats. States can require local utilities to achieve percentage savings of electricity or natural gas sales as compared to a business-as-usual case. Some states specify cumulative savings by a certain period, some establish annual savings targets, and some states specify both an annual and cumulative savings target. In this, states may require annual or cumulative savings with the savings goals increasing over time. Some states also include peak demand reduction in the EERS goals. In Texas, for example, state regulator had initially required utilities to avoid 20% of the forecast increase in peak electric demand through efficiency and DR programs but subsequently increased the target to 30% of demand growth beyond 2013. The utility regulator in Illinois requires new electricity savings that will increase to 2% of sales each year while North Carolina allows measures such as energy efficiency and DR to meet up to 25% (rising to 40%) of its renewable portfolio standard.[120]

In the United States, there are currently 22 states with a mandatory EERS and 4 states with a voluntary EERS (non-binding). Together, these states serve 104.6 million customers.[121] The options that help electric and natural gas utilities achieve their EERS targets include: demand-side management (DSM), demand response, building codes, and in some cases distribution energy systems and combined heat and power (CHP) systems. Some states have also provided the flexibility to use a market-based trading system of energy savings certificates to meet the EERS.[122]

Peak demand mandates have recently emerged as another policy mechanism to encourage DR. In Pennsylvania, the state legislative body passed the Act 129 in October 2008, which required electric utilities to reduce total annual weather-normalized energy consumption by 3 percent and peak demand by 4.5 percent over the 100 hours of the highest demand by May 31, 2013. The act included a provision requiring failure to achieve these reductions in consumption and peak demand exposed utilities to significant financial penalties.[123] The Colorado legislature passed HB-07-1037 in April 2007, requiring the Colorado Utilities Commission to establish peak demand reduction goals for the state's investor-owned electric and gas utilities. The statute sets an overall multi-year statewide peak demand reduction goal of at least 5 percent of the retail system peak in the base year (2006) to be met by the end of 2018.[124]

Reforming utility business models

In May 2016, New York Public Service Commission (NYPSC) issued an order to approve landmark reforms restructuring of utility regulations that helps utilities meet the clean energy goals set forth in Reforming the Energy Vision (REV), the New York State's strategy launched in 2014 to fight against climate change and grow the State's economy by spurring investment in clean technologies like solar, wind, and energy efficiency and generating 50 percent of the state's electricity needs from renewable energy by 2030. The PSC order aims to "moves New York away from decades of rate-setting decisions which encouraged investment in large, centralized power system… Utilities will be required to develop a more efficient and cleaner network through retail markets for distributed energy resources like solar, geothermal, wind, fuel cells,

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[120] https://www.ase.org/resources/energy-efficiency-resource-standard-eers
[121] https://www.ase.org/resources/energy-efficiency-resource-standard-eers
[122] http://www.c2es.org/us-states-regions/policy-maps/energy-efficiency-standards
[123] http://www.pjm.com/~/media/library/reports-notices/demand-response/20170628-pjm-demand-response-strategy.ashx
[124]http://www.leg.state.co.us/clics/clics2007a/csl.nsf/fsbillcont3/5EA2048E8A50B21287257251007B8474?Open&file=1037_enr.pdf

combined heat and power and battery storage, energy efficiency, and other advanced energy services. These new products and services help customers manage their energy usage and reduce their energy bills by creating a two-way, ‘transactive’ grid between customers and energy providers.”[125]

The order reforms the utility business and revenue model and aligns utility profits with key REV goals such as reducing demand, avoiding costly infrastructure projects, and encouraging distributed generation by converting regulated utilities into distribution system platform providers who facilitate the deployment of various third party distributed energy resources (DERs) on the grid. With the reform, utilities are allowed to earn a regulated rate of return from using distributed generation, demand-side management, or other alternative resources to meet power needs instead of relying on transmission line or central station power plant. Under the order, utilities can also earn revenues from "market-facing platform activities" — services that utility provide to DER developers to facilitate their deployment and interconnection. Further, the order allows utilities to benefit from the "Earning Adjustment Mechanisms" — performance-based incentives that incentivize utilities based on (1) power system efficiency assessed by a combination of peak reduction and load factor improvement, (2) energy efficiency that meets higher targets beyond the currently approved targets, (3) interconnection linked to renewable energy developers’ satisfaction with utility assistance in grid interconnection, and (4) customer engagement tied to customer uptake in specific programs.

[125]http://www3.dps.ny.gov/pscweb/WebFileRoom.nsf/ArticlesByCategory/9B4FB5513905CB5985257FB8006DAD48/$File/pr16028.pdf?OpenElement