THE VALUE OF ECONOMIC DISPATCH

A REPORT TO CONGRESS
PURSUANT TO SECTION 1234
OF THE
ENERGY POLICY ACT OF 2005

Prepared by
United States Department of Energy

November 7, 2005

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LIST OF ACRONYMS

AGC	automatic generation control
ATC	available transmission capability
Btu	British Thermal Unit
CAISO	California Independent System Operator
Department	United States Department of Energy
EPAct	Energy Policy Act of 2005
EPSA	Electric Power Supply Association
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FTR	financial transmission right
IPP	independent power producer
ISO	independent system operator
ISO-NE	New England Independent System Operator
kWh	kilowatt-hour
LMP	locational marginal price
MCP	market-clearing price
MISO	Midwest Independent System Operator
MW	megawatt(s)
MWh	megawatt-hour
NERC	North American Electric Reliability Council
NUG	non-utility generator
NYISO	New York independent system operator
PJM	PJM Interconnection
OOM	out of merit order
QF	qualifying facility
QSE	qualifying scheduling entity
RMR	reliability must run
RTO	Regional Transmission Organization
SCED	security-constrained economic dispatch
SCUC	security-constrained unit commitment
SPP	Southwest Power Pool
TTC	total transmission capability
U.S.	United States
WECC	Western Electricity Coordinating Council

SECTION 1

INTRODUCTION AND SUMMARY

Section 1234[1] of the Energy Policy Act of 2005 (EPAct) directs the U.S. Department of Energy (the Department) to:

1) study the procedures currently used by electric utilities to perform economic dispatch;

2) identify possible revisions to those procedures to improve the ability of non-utility generation resources to offer their output for inclusion in economic dispatch; and

3) analyze the potential benefits to state and national residential, commercial, and industrial electricity consumers of revising economic dispatch procedures to improve the ability of non-utility generation resources to offer their output for inclusion in economic dispatch.

EPAct defines "economic dispatch" to mean "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities" [EPAct 2005, Sec.1234 (b)].

EPAct requires the Secretary of Energy to submit a report on economic dispatch to Congress and the states no later than 90 days following enactment of the act and annually thereafter. The study is to include any recommendations that the Secretary chooses to make to Congress and the states concerning legislative or regulatory changes related to economic dispatch [EPAct 2005 at Sec. 1234 (c)]. This report fulfills that statutory requirement. As explained below, the remaining sections of this document present information gathered for this report through a survey of stakeholders and a literature review, including how economic dispatch is practiced in the U.S., its benefits, practices and rules that are identified as obstacles to optimal participation of non-utility generators (NUGs) in economic dispatch, and suggestions for modifications and future research on economic dispatch.

Industry Changes

Electric utility investment practices and operation have been designed to ensure affordable, reliable electricity service to consumers. Affordability and reliability require thoughtful, long-term investments in generation and transmission as well as sophisticated operation of these assets. Economic dispatch focuses on short-term operational

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[1] Section 1832 of EPAct, in identical language, also directs the Department to study the benefits of economic dispatch. This report responds to both sections.

decisions, specifically how to best use available resources to meet customers' electricity needs reliably and at lowest cost.

Ensuring the best use of available resources is much more than a mechanical process of minimizing the total variable cost of electricity production. In seeking lowest-cost production, economic dispatch practices must take into account several factors, including: the continuous variation in loads and generators' inability to respond instantaneously; the need to maintain reserves and plan for contingencies in order to maintain reliability; and the scheduling requirements imposed by environmental laws, hydrological conditions, and fuel limitations.

The nature of utilities has changed as some areas of the country have structurally unbundled and reorganized aspects of their generation and transmission systems. Utility generators have been supplemented by NUGs, built without a guaranteed franchise of customers to buy their output. In 2003, NUGs (including generation that was once utility owned but sold to independent power producers as well as generation owned by unregulated utility affiliates) accounted for 38 percent of total U.S. generation capacity and 27% of actual electricity production (Energy Information Administration, December 2004).

Oversight of utilities' performance in achieving affordable and reliable electricity has been a primary responsibility of state and federal regulatory agencies as well as local authorities and boards, depending on the form of ownership and organization of each utility. Thus, regulatory and ownership policies have an important effect on how economic dispatch is practiced by each utility or other dispatching entity. These policies affect whether the utilities that manage transmission systems own generation, the degree to which utility-owned generation competes with non-utility generation, and whether regional transmission organizations and independent system operators have been developed to manage the transmission system and generation dispatch across a wide geographic area.

Study Method and Overview

For this study, the Department used a survey to solicit state and stakeholder input about economic dispatch. The survey was distributed to stakeholders in late August 2005 with the assistance of seven associations: the American Public Power Association, the Edison Electric Institute, the Electric Power Supply Association, the Electric Consumers Resource Council, the National Rural Electric Cooperatives Association, the North American Electric Reliability Council, and the National Association of Regulatory Utility Commissioners. Appendix A contains the survey questions and the letters sent to these seven organizations. The Department appreciates the cooperation and assistance of these groups in completing this study.

The Department asked for survey responses to be submitted by e-mail by September 21, 2005. Ninety-two responses were submitted, from every sector of the industry and stakeholder community. The respondents and other study participants are listed in

Appendix B, and the detailed responses are posted on the DOE website at **http://www.electricity.doe.gov**. Information quoted in this report is identified as coming from survey respondents or participants. The survey responses greatly aided preparation of this study, and the Department is grateful to the organizations and individuals who took the time to share their views on economic dispatch.

Economic dispatch is a straightforward concept: costs to serve a given level of electricity demand are minimized by dispatching lower-cost generation before dispatching higher-cost generation. A number of considerations must be addressed to ensure that the resulting system operation is secure and reliable as well as lowest cost. **Section 2** explains how economic dispatch is practiced across the U.S., as reported by the survey respondents, and reviews security-constrained economic dispatch (SCED) and security-constrained unit commitment (SCUC). Section 2 also addresses factors that constrain and complicate economic dispatch.

The EPAct directs the Department to study the benefits of economic dispatch for electricity consumers and NUGs. Given the short time available for this study, it was not possible to conduct a new quantitative analysis, so this report reviews studies of economic dispatch performed to date. Most of these studies fall into two categories – those that simulate economic dispatch over a broad region to study the impact and cost-effectiveness of a new Regional Transmission Organization (RTO), and those that look at a defined geographic region and estimate the impact of substituting non-utility generation for less efficient utility-owned production. **Section 3** summarizes the findings regarding the benefits and impacts of economic dispatch in the studies reviewed for this report.

EPAct directs the Department to identify possible revisions to economic dispatch procedures that would improve the ability of NUGs to offer their output for sale under economic dispatch. This study concludes that because economic dispatch (or its more specific forms, SCED and SCUC) is a relatively mechanical optimization exercise, the real issue is not whether economic dispatch procedures are faulty, but rather what rules and practices might be preventing non-utility generation from participating appropriately in the economic dispatch process. **Section 4** reviews practices and rules that have been cited as obstacles to optimal participation of these entities in economic dispatch.

Section 5 lists suggestions for modifying economic dispatch as well as suggestions about how the Department might frame its future work in this area.

Summary of Findings

<u>The Benefits of Economic Dispatch</u>

Economic dispatch benefits electricity users in a number of ways. By systematically seeking the lowest cost of energy production consistent with electricity demand, economic dispatch reduces total electricity costs. To minimize costs, economic dispatch typically increases the use of the more efficient generation units, which can lead to better fuel utilization, lower fuel usage, and reduced air emissions than would result from using less-efficient generation. As the geographic and electrical scope integrated under unified economic dispatch increases, additional cost savings result from pooled operating reserves, which allow an area to meet loads reliably using less total generation capacity than would be needed otherwise. Economic dispatch requires operators to pay close attention to system conditions and to maintain secure grid operation, thus increasing operational reliability without increasing costs. Economic dispatch methods are also flexible enough to incorporate policy goals such as promoting fuel diversity or respecting demand as well as supply resources. Over the long term, economic dispatch can encourage new investment in generation as well as in transmission expansion and upgrades that enhance both reliability and cost savings.

In principle, all generation and transmission dispatchers practice economic dispatch to reduce the cost of serving loads. Economic dispatch reduces total variable production costs by serving load using lower-variable-cost generation before using higher-variable-cost generation (i.e., by dispatching generation in "merit order" from lowest to highest variable cost). Retail customers will benefit if the savings are passed through in retail rates. Economic dispatch can reduce fuel use when it results in greater use of lower variable cost, higher-efficiency generation units than of lower-efficiency units consuming the same fuel.

Understanding Economic Dispatch

Economic dispatch principles and operation are the same in both regulated utility operations and centralized wholesale markets. In centralized markets, the merit order of available resources is determined using offer schedules for each resource rather than the variable production costs that are used to dispatch a set of utility-owned resources.

Many factors influence economic dispatch in practice. These include contractual, regulatory, environmental, scheduling, unit commitment, and reliability practices and procedures. Because economic dispatch requires a balance among economic efficiency, reliability, and other factors, it is best thought of as a constrained cost-minimization process.

It is useful to divide economic dispatch practices in two separate stages: unit commitment and unit dispatch. Unit commitment takes place before real-time operation and determines the set of generating units that will be available for dispatch. Unit dispatch occurs in real time and determines the amount of generation needed from each available unit. Most utilities, regional transmission operators (RTOs), and independent system operators (ISOs) that perform economic dispatch modify least-cost dispatch to account for grid conditions and operational reliability needs; this is called security-constrained economic dispatch (SCED). In real time, many of the adjustments to least-cost dispatch are to prepare for or respond to contingencies that affect grid reliability.

State and federal regulation affects economic dispatch either explicitly through formal rules or implicitly through prudence reviews aimed at ensuring that dispatch minimizes the cost of serving load. State public utilities commissions have principal responsibility for oversight of economic dispatch by investor-owned utilities. The Federal Energy Regulatory Commission (FERC) has primary responsibility for oversight of economic dispatch by ISOs and RTOs. Oversight of economic dispatch by public power and cooperatives is the responsibility of their respective governing boards.

Economic Dispatch Studies

After reviewing recently published studies and responses to the survey, the Department finds that:

1) Studies evaluating the potential for benefits from changes to current economic dispatch practices can be grouped into two categories: studies of the impact of FERC policies encouraging formation of Regional Transmission Organizations ("RTO studies") and studies of the dispatch of IPPs ("IPP studies"). These two types of studies were not designed to present comprehensive information on economic dispatch benefits disaggregated by geographic region and customer class, as envisioned by Section 1234.

2) RTO studies compare centralized dispatch of a large portfolio of generating units (both utility owned and non-utility owned) aggregated over multiple control areas to the current practice of simultaneous, independent dispatch of subsets of this portfolio by individual control areas. RTO studies have found economic dispatch benefits ranging from \$80 million to over \$40 billion, depending on the region and length of time studied. Normalized, these benefits range from one to five percent of total wholesale electricity costs.

3) IPP studies compare dispatch of a combined fleet of new (typically non-utility owned) and existing (typically primarily utility-owned) generating units within a single control area to the current practice of dispatching existing generating units. IPP studies have found economic dispatch benefits ranging from \$30 million to over \$900 million, depending on the region and length of time studied. Normalized, these benefits range from eight to more than thirty percent of total variable production cost.

4) Both RTO and IPP studies rely, for the most part, on production cost simulation methods, which seek to replicate least-cost dispatch of a specified fleet of generation. However, modeling practices vary, and the modeling methods are sometimes limited in their ability to evaluate all aspects of actual dispatch procedures.

5) Several important dispatch procedures and practices will require more detailed treatment if they are to be studied adequately using production cost simulation methods.

Economic Dispatch Problems

NUG complaints about economic dispatch revolve around allegations that vertically integrated utilities use their dispatch processes to favor utility-owned generation over non-utility-owned generation. However, because economic dispatch is a relatively mechanical process, it appears that many of the concerns that NUGS see as ineffective economic dispatch are more accurately viewed as rules and practices that exclude NUGs (and other resources) from the economic dispatch stack. These practices include determinations of whether NUGs receive long-term contracts to sell their production to load-serving entities, whether they can secure sufficient transmission capacity to deliver their production to host utility loads or more distant purchasers, and whether NUGs provide sufficient operational flexibility to provide maximum operational value to the grid.

Potential Modifications to Economic Dispatch

There is room to improve economic dispatch practices to reduce the total cost of electricity and increase grid reliability. The FERC-State Joint Boards on Economic Dispatch (created pursuant to Sec. 1298 of EPAct) may wish to study these, starting with a more detailed examination of economic dispatch practices and administration than was possible in this limited study. Similarly, FERC may choose to address some of the obstacles that keep NUGs out of the dispatch stack in the context of its plan to review Order 888. In addition, DOE urges the NUG and power purchaser communities to work together to clarify and revise contract and operational considerations so that contract terms recognize and compensate NUGs for providing greater operational flexibility. The quality and accuracy of economic dispatch tools and load forecasting need further improvement. Last, further quantitative analysis and modeling of the benefits of economic dispatch should address a number of important details and considerations.

"Economic" Dispatch vs. "Efficient" Dispatch

In recent weeks there has been intense interest in the Congress in whether economic dispatch practices could or should be modified to ensure the most efficient use of scarce natural gas in gas-fired generation units. "Economic dispatch" is an optimization process crafted to meet electricity demand at the lowest cost, given the operational constraints of the generation fleet and the transmission system. Although economic dispatch will usually run higher efficiency gas-fired units before lower efficiency units, that is not always the result, for a number of possible reasons. (See pp.13-20 below for more detail.) "Efficient dispatch" would presumably seek to modify the practice of economic dispatch to ensure that more efficient gas-fired units are *always* used before less efficient units.

Despite DOE's interest in ensuring the efficient use of natural gas for electricity generation and other purposes, it remains skeptical of the merits of "efficient dispatch," for several reasons. First, the fundamental purpose of economic dispatch is to reduce consumers' electricity costs. "Efficient dispatch" would take the dispatch process off this path and increase consumers' electricity costs – for benefits that may not be large enough to offset these additional costs. Second, economic dispatch is at best a complex process, and modifications to it must be made with care in order to minimize unanticipated consequences. Modifying it to achieve short-term non-economic policy objectives should be considered only as a last resort. Third, a better alternative would be to examine the practice of economic dispatch itself to determine whether modifications are needed to better achieve its traditional objectives – which could by itself lead to more efficient use of natural gas. A review of this kind could be pursued through the regional joint FERC-State boards created by EPAct in Sec. 1298.

SECTION 2

ECONOMIC DISPATCH

For much of the past century, vertically integrated utilities conducted economic dispatch within their individual control areas, meaning that each utility coordinated the operation of its own generators to deliver electricity efficiently across its own transmission lines to serve its own customers. The utility's dispatchers knew the capabilities and costs of the firm's resources and the strengths and weaknesses of its transmission system. Sometimes they purchased energy from outside the firm's own system and deliberately shipped ("wheeled") electricity across other utilities' transmission lines.

Those practices began to change several decades ago with the growth in inter-regional bulk energy sales (as with hydropower sales from Quebec into New York and seasonal exchanges between California and the Pacific Northwest) and the proliferation of "qualifying facilities" (QFs) under the Public Utilities Regulatory Policy Act of 1978. QFs' energy production had to be integrated in real time with a utility's own power production and transmission flows. It also became apparent that significant economies could be achieved if several utilities within a region operated their plants in a single power pool for integrated dispatch; pooling took place primarily in the northeastern U.S. with the formation of the Pennsylvania-New Jersey-Maryland, New England, and New York power pools. Because each of these areas had a highly networked transmission system, the member utilities could reduce the both energy and capacity costs for their customers through pooled dispatch and reserve-sharing.

What is Economic Dispatch?

"Economic dispatch" has a common, general meaning – the practice of operating a coordinated system so that the lowest-cost generators are used as much as possible to meet demand, with more expensive generators brought into production as loads increase (and conversely, more expensive generation eliminated from production as load falls). Most people agree with EPAct's definition of economic dispatch – "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities" – but the details of how this definition is put into practice can vary significantly.

Electricity loads vary over time, rising and falling in daily and weekly patterns. Because electricity travels at the speed of light and cannot be stored inexpensively, generation must be available that can follow changes in load almost instantaneously. However, generators vary widely in their costs and capabilities; fossil-fired units with low marginal costs tend to be relatively inflexible, and generators that can follow load tend to be more expensive. Generators are also subject to fuel limitations and environmental regulations that restrict their availability. Finally, reliability considerations demand that excess generation be available in reserve, along with transmission capacity, to respond to sudden, unplanned contingencies.

These characteristics of the power system lead to a natural sequencing in system operations -- first, determine which units should be turned on and made available to serve loads (called unit commitment), and, second, determine how much production to call from each resource (economic dispatch). To better define the terms:

- Economic dispatch is the economic optimization process that determines a combination of generators and levels of electricity output to meet demand[2] at the lowest cost, given the operational constraints of the generation fleet and the transmission system.

- Security-constrained[3] economic dispatch (SCED) is an economic optimization process that searches for the set of resources and production levels available at a specific point in real time that minimizes the cost of electricity production, subject to a variety of operational constraints to assure reliable grid operations. Adequate reliability practices comply with the reliability practices and standards of NERC, or those that will be adopted by FERC under the recently enacted EPAct. Organizations that practice SCED check system conditions and re-optimize dispatch instructions frequently (usually every five minutes). Economic dispatch uses the resources available on the system for the time frame under analysis.

- Security-constrained unit commitment (SCUC) searches for a least-cost reliability solution by identifying the appropriate mix of units (capacity) to meet projected loads. SCUC is an optimization process that is typically run one day ahead of actual dispatch. This process looks at expected demands, resource availability, and system conditions and finds the combination of resources that should be committed to operate the next day to produce the least-cost mix of energy and reserves subject to expected operational considerations (such as start-up costs and times, minimum run levels, and ramp rates) and grid constraints. Entities that practice SCUC perform the analysis one or more times during the day preceding the dispatch day and issue commitment orders around 5 or 6 p.m. for the units needed the next day. Dispatchers who perform SCUC then conduct SCED for daily operations, but not every dispatching entity that performs SCED first conducts SCUC.

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[2] The electricity industry refers to the system's ability to meet peak load as system "adequacy."

[3] The electricity industry uses "security" to mean the ability of the transmission system to withstand changes or contingencies on a daily and hourly basis. NERC rules followed by all industry members require that each grid manager operate its system at all times so that it can withstand the loss of the specific grid facility that would cause most harm to system conditions (called the "N-1 contingency") and be able to restore stability and be prepared for the loss of the next-worst contingency within 30 minutes.

As indicated above, economic dispatch works to manage resources across time. Different resources have differing production capabilities and characteristics. A generator's production level this afternoon will be affected by its on-line status and production levels this morning and yesterday (e.g., a baseload coal plant or a hydroelectric pumped storage plant) as well as whether maintenance was performed on it last quarter or last year (e.g., nuclear refueling or a load-following plant that undergoes maintenance in non-peak months). This means that although the primary focus of economic dispatch is daily and minute-to-minute operations, the process must look beyond a single day to optimize the operation and cost of resources across a season.

Economic Dispatch vs. Efficient Dispatch

In a recent hearing of the Senate Energy and Natural Resources Committee*, there was great interest in determining whether economic dispatch practices could or should be modified to ensure the most efficient use of scarce natural gas in gas-fired generation units. "Economic dispatch," as noted above, is an optimization process crafted to meet electricity demand at the lowest cost, given the operational constraints of the generation fleet and the transmission system. Although economic dispatch will *usually* run higher efficiency gas-fired units before lower efficiency units, that is not always the case, for a number of possible reasons. (See pp. 13-20 below for more detail.) "Efficient dispatch" would presumably seek to modify the practice of economic dispatch to ensure that more efficient gas-fired units are *always* used before less efficient units.

Despite DOE's interest in ensuring the efficient use of natural gas for electricity generation and other purposes, it remains skeptical of the merits of "efficient dispatch," for several reasons:

- The fundamental purpose of economic dispatch is to reduce consumers' electricity costs. "Efficient dispatch" would take the dispatch process off this path and increase consumers electricity costs – for benefits that may not be large enough to offset these additional costs.
- Economic dispatch is at best a complex process, and modifications to it must be made with care in order to minimize unanticipated consequences. Modifying it to achieve short-term non-economic policy objectives should be considered only as a last resort.
- A better alternative would be to examine the practice of economic dispatch itself to determine whether modifications are needed to better achieve its traditional objectives – which could by itself lead to more efficient use of natural gas. A review of this kind could be pursued through the regional joint FERC-State boards created by EPAct in Sec. 1298.

*Senate Committee on Energy and Natural Resources, Full Committee Hearing – Hurricane Recovery Efforts, October 27, 2005

Security-Constrained Unit Commitment

All North American electricity industry dispatchers use economic dispatch; many use SCED; and many also use some form of SCUC in addition to SCED. This study uses the term "economic dispatch" broadly, as in the statutory definition, to mean the generic task of least-cost optimization subject to operational constraints; the more specific terms SCED and SCUC are used in discussing certain applications and implications of economic dispatch.

SCED coordinates the production levels of available resources to meet loads in a grid-secure fashion in real time, and SCUC increases the likelihood that the most cost-effective and reliability-supportive resources will be available to be dispatched. However, not every organization that performs SCED performs SCUC in advance.

Shahidehpour, Yamin and Li (2002) describe the process:

> Three elements are included in the SCUC paradigm: supplying load, maximizing security, and minimizing cost. Satisfying the load is a hard constraint and an obligation for SCUC. Maximizing security is often satisfied by maintaining sufficient spinning reserve at less congested regions that could easily be accessed by loads. Cost minimization is realized by committing less expensive units while satisfying the corresponding constraints and dispatching the committed units economically.

To operate the grid reliably in real time, it is necessary to have capacity in excess of the day's anticipated demand. This capacity must be fully synchronized to the system, unloaded, and able to respond immediately to dispatch instructions and be fully available within 10 minutes to serve load. Some of this capacity must be available in specific locations to address anticipated voltage, thermal, or stability need or to serve load on the short side of a transmission bottleneck. Some can be baseload or block-loaded (i.e., scheduled at a fixed output level for one or more hours), but some must be load-following units able to respond to automated dispatch instructions in real time (called Automatic Generation Control (AGC)) in order to match moment-to-moment changes in load.

SCUC is the exercise of conducting a modified form of economic dispatch for grid, load, and resource conditions in the very near future, to assure that the appropriate resources will be operational when they are needed for economic dispatch. Where it is practiced, SCUC produces energy, regulation, and reserve schedules for generators and loads for each of the 24 hours in a dispatch day. Where SCUC is coordinated by a market and system operator such as the New York ISO (NYISO), New England ISO (ISO-NE), or PJM Interconnection (PJM), SCUC also calculates day-ahead prices for energy and ancillary services for each generation location; those prices reinforce the ISO/RTO's unit commitment orders by providing a binding financial incentive for the generator to operate reliably.

Generators that are not committed under SCUC can either sell their output elsewhere under short-term contracts or can remain off line on the dispatch day. As American Transmission Company points out, if the unit commitment process results in insufficient resources to meet the dispatch day's actual load, the universe of resources available for SCED could come up short, exacerbating reliability challenges or raising total production costs for the dispatch day.[4]

Grid Conditions that Constrain Economic Dispatch

Security constraints limit economic dispatch options because grid operational conditions affect which combinations of resources will be able to meet loads and maintain the grid in a secure state. Grid reliability rules require that system operations respect voltage, thermal, and stability limits for individual grid assets (such as transmission lines and generators). To preserve secure operations, operators must always work with a combination of assets and loading that allows the system to lose its most security-valuable asset (called the "N-1 contingency") and be restored to a secure condition within 30 minutes. Security constraints determine which flows from which generators will support or compromise reliable grid operations.

Factors that affect and dictate grid security constraints include:

- Generation and transmission facility conditions and availability (e.g., whether a unit or line is out of service for maintenance or must operate under reduced limits);

- Line capacities under different power flows and loadings;

- Ambient weather, particularly temperature and wind speeds, which affect a line's thermal performance;

- The availability and capabilities of other grid facilities, including circuit breakers, series or shunt reactive devices, transformers, and other equipment and protection schemes to buffer and manage line loadings and voltages.

Further, load forecasts affect the level of resources and the unit-specific production levels assumed to be required to reliably serve the forecasted load. The accuracy of the load forecasts affects the calculations of how large a reserve margin is needed to maintain short-term grid reliability for day-of and day-ahead purposes.

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[4] The citation above refers to American Transmission Company's response to the Department's August 2005 survey on economic dispatch. All subsequent comments or quotations are drawn from the indicated respondent's survey comments unless otherwise noted. Appendix B lists the survey respondents, and the full text of the survey responses are posted on a Department website at **http://www.electricity.doe.gov**.

Resource Considerations Affecting Economic Dispatch

A variety of physical, environmental, and regulatory considerations affect how resources can be used and combined in the economic dispatch process, and a combination of attributes determines how each generation resource is identified and treated in the process. Depending on the dispatch regime, those factors may include:

- Real and reactive energy-production capacity;
- Whether a unit is on a cost-based, reliability-must-run (RMR) contract or its production cost curve is based on fuel costs and efficiency rates (or, in centralized wholesale markets, bids for production at differing levels on its output curve);
- Variable operations and maintenance costs;
- Start-up costs;
- A unit's mechanical or economical upper and lower production levels;
- Unit ramp rates within the range of production levels (e.g., the time it takes to move from one production level to another while respecting the turbine's safe thermal gradients);
- Minimum sustained production levels (to keep the unit available for the next hour or next day);
- Emissions limits and costs of emission allowances (because units that use up their emissions allowances prematurely may not be available to operate during peak periods);
- A unit's availability on the date and time in question (which might be affected by factors such as inclement weather, prior performance problems, or fuel availability);
- For a hydro, wind, or other intermittent units, a forecast of expected unit production levels at different points in the dispatch period;
- Contracts or other requirements that assign a unit must-run or must-take status so that is not fully dispatchable;
- A unit's prior commitments to make off-system sales; and
- A unit's ability and contractual requirement to deliver ancillary services, such as reactive power or quick-start capability.

Some of these factors, such as minimum production levels, will dictate whether a unit will be in the base level or the competitive region of the economic dispatch stack.

A number of respondents to the Department's survey pointed out that requirements of state public utility commissions and environmental regulations affect utility resource procurement and dispatch, and that these state- or utility-specific operating requirements must be taken into account in an individual utility's dispatch practices. Technically speaking, these requirements are treated as "constraints" in the cost-minimization procedures used by the utilities for economic dispatch. These concerns can be reflected in the dispatch process, whether as formal limitations on the selection of resources or as qualifiers on the utilization of specific resources:

- The financial condition or credit quality of the generator, on the principle that if the generator is not financially sound it should not be viewed as a reliable source to meet the utility's obligation to serve retail customers;

- State or corporate requirements for renewable production, use of in-state coal-fired generation, or fuel diversity;

- Whether the generator has both a firm fuel supply and firm fuel transportation, so it can perform reliably when dispatched;

- Whether the unit's fuel source has take-or-pay provisions that would make it more expensive to idle than to run;

- Whether the dispatching entity or its regulators explicitly attempt to minimize environmental impacts such as air emissions from generation;

- Whether the area needs to maximize its efficiency of natural gas use because of high natural gas prices or limited deliverability.

Security-Constrained Economic Dispatch

SCUC sets up the collection of resources that will be needed to operate the grid reliably in real time. Once SCUC establishes the mix of resources available for dispatch in real time, SCED is the iterative process in which the available units are dispatched to ensure both reliability and cost minimization. The SCED process first looks for the least-cost, merit order dispatch solution. Next, all significant, credible contingencies are considered, such as the unplanned loss of a generating or transmission facility. Usually, the contingencies are considered individually, one at a time; in some cases, double contingencies are considered. If a contingency would result in a violation of a thermal, voltage, or stability limit, the system is redispatched using the next-best available generation pattern and restudied to ensure that the contingency would not lead to a violation. Redispatch to assure system reliability typically causes some units to be dispatched out of merit order (OOM).

In regions managed by ISOs and RTOs and where transmission bottlenecks limit the amount of low-cost energy that can flow through to load, the dispatcher will redispatch out-of-merit (more expensive) energy from a local source to manage around the congestion. In these cases, the cost of redispatch (which is revealed through differences among locational marginal prices (LMPs)) can be mitigated by allocation of congestion hedging rights. Redispatch to manage around transmission bottlenecks and congestion also takes place outside ISO/RTO markets, but when it happens within integrated utilities, the costs are absorbed and allocated to all customers without explicit accounting.

Current Practices in Building the Economic Dispatch Resource Stack

In economic dispatch theory, every resource has a schedule of production levels and costs that reflects its start-up time, ramp rates, and the like. All available units for a specific point in time are "stacked" in order from lowest to highest cost per megawatt hour (MWh), and the least expensive units are dispatched in increasing cost order until customer demands (plus line losses and operating reserves) have been met. The dispatch process is repeated over and over. When resources are dispatched from least to most expensive, this is termed "merit order dispatch."

In practice, it is far more complicated to build the economic dispatch resource stack. For a variety of reasons, some of which are explained below, a number of resources are not required to compete for a slot in the dispatch order on the basis of cost alone but are "forced" into the stack at certain places and become part of the set of constraints that limit the dispatch opportunities for the remaining resources. The elements of the economic dispatch stack are illustrated in Figure 1.

<u>Minimum-Run Production</u>

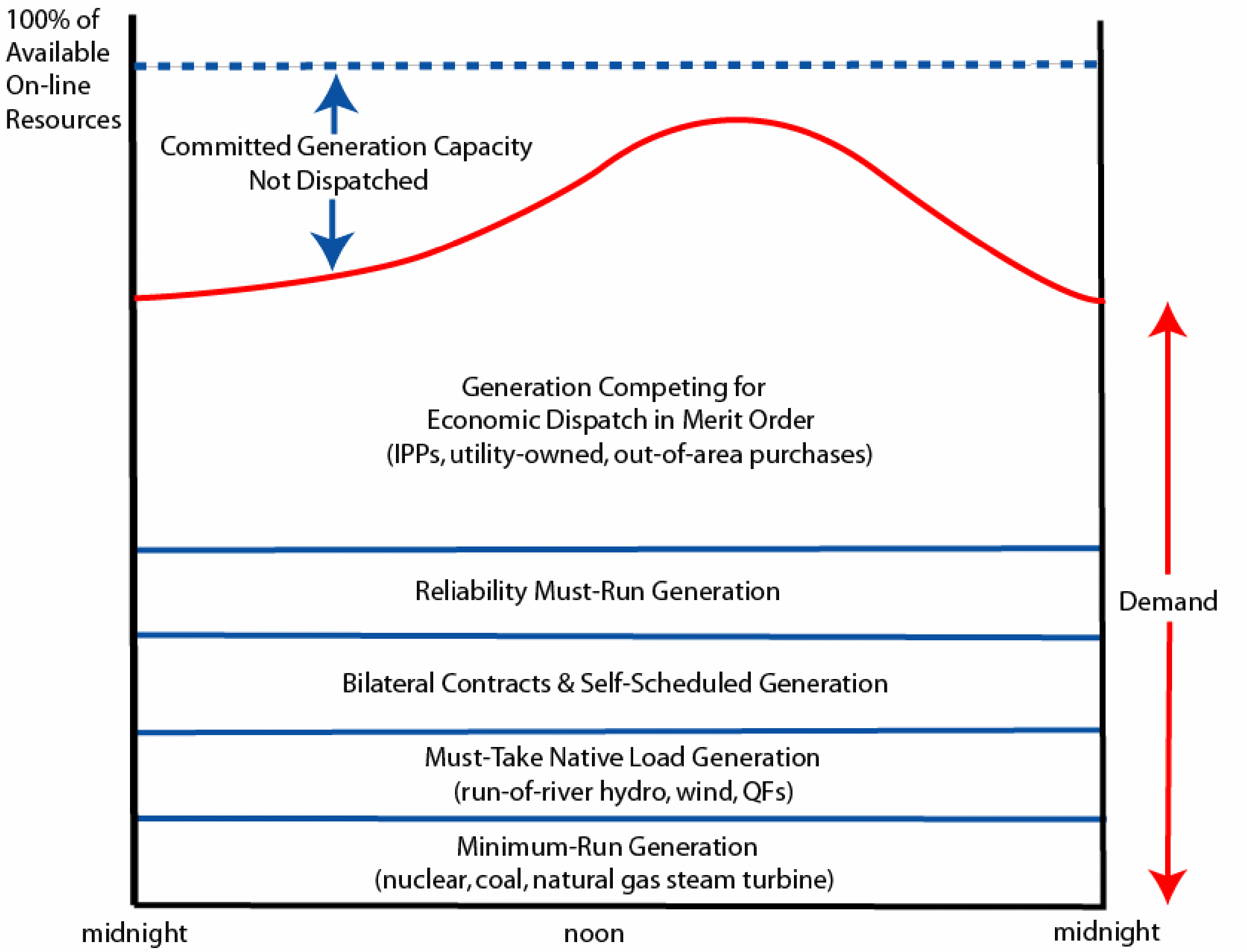
Large baseload units, such as coal, nuclear, and gas combustion, typically have low per-MWh marginal operating costs but require a lengthy start-up period during which their production is not very fuel-efficient. To have such units available to meet baseload demand or as load-followers, dispatchers frequently operate them at or above their minimum-run levels (i.e., above the point where production becomes efficient). These minimum-run levels are forced into the dispatch stack regardless of the units' production costs within the minimum-run range; their production above the minimum-run levels competes for merit-order dispatch.

<u>Self-Scheduled Generation and Bilateral Contracts</u>

Within an area that is under economic dispatch, load-serving entities and generators always have the option of securing energy supplies or sales through self-generation or bilateral contracts, subject to grid reliability. Within any dispatch area, production that is pre-committed and not available for dispatch must be carefully coordinated with and integrated into the dispatch algorithm because the flows from those resources affect transmission flows and grid conditions and thereby constrain the dispatch options.

Figure 1

Building the Economic Dispatch Stack



Economic dispatch accommodates self-dispatch (when a utility commits its owned generators exclusively to serve a portion of its native load) and bilateral contracts by fixing the volumes committed from specified plants into the non-discretionary portion of the stack.

Within the economic dispatch stack, self-dispatch and bilaterals are block-loaded and scheduled at the production levels and times nominated, rather than scheduled based on economic optimization. In market dispatch, they are not recognized as having an operational cost that must be integrated into the optimization but are treated as price takers; in reality, regardless of the market-clearing price, those transactions are settled outside the market at the predetermined price set in the contract between the buyer and seller. Only amounts actually purchased from the market are priced at the market-clearing price.

NUG contracts that are negotiated as non-dispatchable are treated as bilaterals or must-run production. The Electric Power Supply Association (EPSA) observes that some utilities are reluctant to enter into forward bilateral contracts with independent power producers (IPPs), so they first exhaust all utility-owned generation options before turning to NUGs for spot-market (daily or hourly) purchases. Mid-American indicates that "it is typically the terms and conditions of the NUG power purchase agreements, other than price, that determine how NUG is dispatched."

Economic dispatch treatment of bilateral contracts must recognize the nature of the underlying transmission and energy product being offered because that affects performance certainty. Under the Western Systems Power Pool agreement, three types of products are traded in the Western Interconnection:

- Schedule A is Economy Energy service, which can be interrupted anytime with notice;
- Schedule B is Unit Commitment Service, which is linked to the performance of a specific generating unit;
- Schedule C is firm sales or exchanges.

Calpine notes that economic dispatch does not limit load-serving entities' procurement decisions because most procurement and contracting decisions take place within a long-term state or regional planning and procurement process while economic dispatch focuses on how to manage procured resources in real time for maximum value. Economic dispatch does not change the utility's responsibility to determine an appropriate, balanced portfolio of self-generation and long-term and spot-market purchases, nor does it change the state commission's jurisdiction over regulated utility energy procurement.

Reliability Must-Run (RMR) Production

Some units are recognized as critical for maintaining grid security, to ensure that their production is available to protect against potential N-1 voltage, thermal, or stability problems. However, these units may not be economically competitive compared with other generation and so would not be dispatched under a pure least-cost optimization scheme. These units are included within the dispatch stack as price-takers to be sure that their production is scheduled as needed to meet reliability needs, and they are paid as a function of their costs rather than at the market-clearing price. Such units are often referred to as "reliability must-run," and their schedules are OOM. When RMR resources are dispatched in a centralized market, their actual operational costs often exceed the market-clearing price.

Intermittent, Must-Take Resources

Wind, run-of-river hydro, and QFs are the predominant types of intermittent and must-take resources. Their output levels cannot be controlled by the dispatcher, and there are contractual, regulatory, or cost factors that require these resources to be accepted in full whenever they are available. Forecast schedules for these resources are placed into the dispatch stack and modified in real time to reflect actual production; load-following resources are dispatched to compensate for the relative availability or absence of intermittent, must-take resources.

What's Left for Economic Merit Order Dispatch?

Whether in a stand-alone utility dispatch or a centralized energy market dispatch, the amount of generation that is forced into the stack varies widely. For example, within the PJM area, between 30 and 50 percent of the resources in the dispatch stack can be must-run and baseload units and treated as price-takers; the remainder are under bilateral contracts or are dispatchable resources that receive the market-clearing price.

Within the Electric Reliability Council of Texas (ERCOT), bilateral contracts account for a wide majority of the energy consumed. Qualifying Scheduling Entities (QSEs) participate in the ERCOT market, performing economic dispatch for their own portfolios of resources and loads. They submit the resulting schedules – a combination of fixed resources and competitive resource bid schedules – to ERCOT for coordination and operation of the balancing energy market. After the QSEs' contractual obligations and the OOM units, perhaps only 10 percent of energy in the ERCOT market is actually in the portion of the stack that is optimized competitively by cost and priced at the market-clearing price.[5]

In the Pacific Northwest, the bulk electricity system relies to a large extent on hydroelectric generation, which has major implications for economic dispatch. The Washington Utilities and Transportation Commission explains that hydropower resource management must take into account the region's flood control, fish management, irrigation, recreation, and transportation needs as well as electricity requirements. Hydro

[5] Both LG&E Energy and APPA comment that the organized markets operated by RTOs and ISOs with bid-based SCED use a single-clearing price convention under which "all generators bidding into the market for a particular time interval are paid the price necessary to clear the market in that time interval, even if the bid a chosen generator made was much lower than that clearing price." In practice, the amount of energy receiving the market-clearing price depends on the market, but may range from only five percent (as in the CAISO and ERCOT markets) to 70 percent of the energy consumed (as in PJM). APPA suggests that this practice has significantly raised costs to ratepayers compared to the prior system of cost-based dispatch, with baseload coal and nuclear plants receiving high market-clearing prices set by marginal gas units. This is an issue of market design rather than an issue of economic dispatch *per se* and will not be discussed further in this study.

managers across the region work to optimize streamflows on an annual basis under the Pacific Northwest Coordination agreement, and coordinate daily and hourly hydro facility management of the integrated, interdependent river system under the Mid-Columbia Hourly Coordination Agreement. Although hydropower is one of the lowest-cost resources available, most hydro is used to follow load (thus displacing more costly thermal generation) rather than as a baseload resource.

The Cowlitz, Grant, and Pend Oreille Public Utility Districts explain that:

> Utilities that are largely dependent on hydropower are constantly rebalancing their portfolios to make best economic use of their 'discretionary water': hydro energy that can either be stored for later use or sold into the market now…. Economic dispatch of hydroelectric generation must also take into account the forward opportunity cost of production: what potential future revenues are being foregone if scarce (energy-constrained) fuel is used today to generate power? Owners … maximize the value of their scarce [hydro] fuel in response to market price signals, for example by purchasing power during off-peak periods, holding water in reserve, and generating with hydropower during peak periods. This contributes to the overall value of economic dispatch because a scarce fuel is being used in its highest value period.

Dispatchability – the ability to follow load closely – is an important attribute for resources in the dispatch stack. The Ohio Public Utility Commission observes that "market dispatch focuses on marginal units, which are typically peaking units whose operating characteristics are different from baseload coal-fired units. The real-time five minute economic dispatch used by PJM and MISO to meet reliability requirements does not favor baseload generation but focuses attention on units with quick response times." Xcel comments that "[m]ore non-utility generation would be dispatched if there were requirements for IPPs to sign a contract allowing a control area operator to dispatch its unit on an economic basis at a price agreed to by the parties…." The most valuable load-following capability is operation under AGC, in which the dispatcher sends automatic signals to the generator to change production levels instantaneously as load levels change. To date, few NUGs and dispatching entities have reached agreements that allow full dispatchability with appropriate compensation.

Current Practices for Optimizing Dispatch

Given all the factors outlined above, the dispatching entity takes its stack of fixed and economically ordered resources and attempts to find a cost-minimizing solution that meets expected load plus reserves without violating any grid security constraints.

For example, PacifiCorp dispatches a portfolio of owned generation, generation under contract, and interchange (purchases across balancing area boundaries) transactions "at the lowest available cost for our customers subject to constraints…." The company describes how it treats these resources:

- Coal-fired generation resources are normally dispatched as simple options with the dispatch cost consisting of the fuel cost, environmental cost, and variable operating and maintenance costs. In addition, several of these resources are occasionally used to supply operating reserves (contingency and regulating) for the control areas.

- Natural-gas-fired generation without long-term fuel contracts is normally dispatched as a spark spread option including variable operating, maintenance, and start-up costs. The decision to purchase natural gas and electricity is made in the day-ahead market and again in the hour-ahead market. In addition, several of these resources are routinely used to supply operating reserves (contingency and regulating) for the control areas.

- Hydro generation resources with storage capability are normally dispatched as swing options based on the opportunity cost of dispatching in some other time period. In addition, several of these resources are routinely used to supply operating reserves (contingency and regulating) for the control areas.

- Contractual resources are dispatched either as simple, spark spread, wing, or compound options, depending on the terms of the agreements.

Cost-minimization goals and methods appear to vary across the industry. The National Rural Electric Cooperative Association comments that in areas without ISO/RTO markets, "individual utility control area operators typically utilize their own generators first in their economic dispatch operation, supplemented by any network resources needed to meet their Open Access Transmission Tariff (OATT) requirements and units used to honor sales and purchase commitments to others." Kansas City Power & Light writes, "KCPL has an obligation to utilize the capital assets of the corporation that are included in the rate base to the best advantage of the retail customers. This obligation could, on occasion, require a dispatch order that some may not consider 'economic' based on the short-term but that may prove economic to the retail customer in the long run."

Resources that are not dispatched may offer their generation for sale in real time. Parties that do bilateral trades can use the spot market to supplement or backstop their transactions, buying energy in the spot market when it is less expensive than it would be to self-generate. They can also use spot market energy to meet energy imbalances between their contractual commitments to buy and sell and their actual purchases or sales.

Variations in Economic Dispatch Practices

Economic dispatch can be practiced across a single utility control area, or across multiple control areas by a single utility or other balancing authority[6] on behalf of multiple load-serving entities, transmission operators, and generators. Economic dispatch practices vary by area size and dispatcher type.

<u>Small-Area Dispatch by Single Utilities</u>

A number of survey respondents perform economic dispatch across relatively small areas:

- MEAG Power is a non-profit corporation that serves 49 Georgia communities from its share of two coal and two nuclear units and one combined-cycle generator, for a total of 3,563 megawatts (MW). MEAG meets its customers' 2,050 MW peak load using these resources plus Southeastern Power Administration hydro resources, and commits and dispatches its resources under an operating agreement with Georgia Power.

- The Western Farmers Electric Cooperative (WFEC) is an electricity generation and transmission cooperative in Oklahoma serving about 250,000 meters. WFEC performs economic dispatch to coordinate production from seven member-owned and Southwest Power Administration power plants with a total of 1,633 MW of capacity, plus additional economy energy purchases as available, and modifies dispatch every 60 seconds.

- The Nebraska Public Power District (NPPD) serves 24 public power districts and rural cooperatives, 54 municipal customers, and 87,000 retail customers in Nebraska, with a total peak load of 2,554 MW and a balancing authority load of 3,229 MW. NPPD performs economic dispatch for 3,200 MW of owned generation with purchases and sales as appropriate for reliability and economic efficiency; some of the plants' municipal co-owners (through participation agreements) have the right to independently dispatch their participation amounts.

- Portland General Electric Company in Oregon meets a peak load of 3,800 MW with a combination of company-owned generation and purchased resources by comparing the economic value of the available resources.

[6] "Control area" is the old term describing the geographic area and set of resources under control by a single dispatching utility. Today that dispatching entity is called a "balancing authority," defined by NERC as the "responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time." (NERC 2005)

- Avista reports that, like other generation owners in the Pacific Northwest, it dispatches its own power generation units "based upon supply obligations, the lowest variable economics of the generation units as compared to the market, and various non-power factors" (particularly hydro-generation considerations). Avista owns approximately 1,400 MW of generation capacity and serves a peak load of about 1,500 MW.

- The Hawaiian Electric Company serves five of the six principal Hawaiian islands. It dispatches utility and non-utility generators on an incremental cost curve basis, within the constraints of system operations limits and power purchase agreement requirements.

Mid-American Energy, which manages 4,800 MW of utility-owned owned generation for itself and its joint dispatch customers, describes how its economic dispatch process respects operational constraints:

1) Develop a day-ahead forecast for hourly load to be dispatched;

2) Arrange day-ahead purchases, sales, and/or demand response participation to maximize economy;

3) Commit adequate generating capacity to serve the resulting generation requirements;

4) In real time, dispatch MidAmerican generation and purchases to economically balance the requirements of MidAmerican and its joint dispatch customers; and

5) Maximize system economics by arranging next-hour purchases and sales.

<u>Large-Area Dispatch by Single Utilities</u>

Single utilities can perform dispatch control over large areas:

- Southern Companies perform economic dispatch for about 43,000 MW of nuclear, coal, hydro, pumped-storage hydro, natural gas, oil, and purchased power resources across a 120,000 square mile region. Southern conducts SCUC and SCED, coordinating term and hourly purchase and sale opportunities into the economic dispatch. "If a non-utility generator or other market participant is offering energy at a price that will reduce Southern Companies' production costs, then Southern Companies' traders will attempt to negotiate a purchase. If successful, such a purchase will be scheduled and subsequently incorporated into Southern Companies' unit commitment and real-time economic dispatch processes." Southern reports that during 2004, it purchased more than 2,760 gigawatt hours (GWh) from NUGs; total Southern sales (retail and wholesale) equaled 192,382 GWh, of which 7.2 percent is identified as purchased power (Southern Company 2004 Annual Report).

- Entergy Services, Inc., performs SCUC and dispatch across a three-state region, serving approximately 23,500 MW of load and integrating about 26,500 MW of generation. Entergy reports that purchased power now accounts for 30 percent of its total energy needs, but does not further identify its suppliers.

- PacifiCorp manages two control areas, one in Utah, Wyoming, and Idaho with a summer peak of 6,792 MW, and one in western Oregon, Washington, and California with a winter peak of 6,018 MW. Pacificorp only performs economic dispatch for resources in its system portfolio (although it purchases resources that it does not dispatch).

Southern Companies uses SCUC, selecting appropriate generation resources for the next day (including power purchased from NUGs over hourly, daily, or yearly terms) to minimize the expected costs of serving forecast load:

> Once the unit commitment and power purchase decisions are made, then the real-time economic dispatch process determines the optimal output levels of each dispatchable resource in real-time, based on marginal costs of each resource…. Marginal cost components include the generating resource heat rates (efficiency), commodity cost of fuel, fuel transportation costs, fuel-handling expenses, variable operations and maintenance expenses, emission allowance costs, and transmission losses. In real-time, Southern Companies' Energy Management System utilizes a resource balancing algorithm that measures generation and load balance of Southern Companies' electric system to meet their customers' real-time needs. This automated process captures system load demand, downward-and-upward regulating margin requirements, lower and upper economic and operational limits of each generating unit, maximum ramping rate of each generating unit, each unit's incremental heat rate, and system imbalance energy needs. It also automatically adjusts the output of the generating units that are operating on the margin to meet the instantaneous changes of load on the system…. Unit commitment and economic dispatch processes are subject to redispatch orders from the transmission provider to address transmission reliability constraints. Such orders include the dispatch of must-run generation for reliability purposes and, thus, not committed based on economics.

However, EPSA claims that:

> … In some utility systems – unless the utility has pre-purchased non-utility generation through a bilateral arrangement that includes the right to dispatch that generation – the utility-owned generation is economically dispatched first, and then the non-utility generation is economically dispatched on an as-needed basis…. For non-utility generation, the absence of bilateral contracts results in a sequential approach to dispatch,

which means that more costly, less-efficient utility-owned generation can be operated ahead of less costly, more efficient non-utility generation.

Large-Area Dispatch by RTOs and ISOs

There are seven RTOs and ISOs in the U.S. (Figure 2) that manage grid operations. Three of the seven conduct some form of SCED within one state (NYISO, California ISO (CAISO), and ERCOT), while three perform SCED across many states (PJM, ISO-NE, and MISO). SPP has not yet begun performing SCED.

To envision the breadth of dispatch areas served by the ISOs and RTOs, consider that:

- NYISO coordinates the activities of over 335 generating stations representing 37,500 MW of capacity, plus demand resources.

- ISO-NE runs a dispatch area that coordinates 350 generators to serves 6.5 million meters, with more than 31,000 MW of installed capacity across six states.

- PJM performs economic dispatch over a 14-state, 164,260-square-mile region with a population of 51 million people, coordinating 163,800 MW of resources.

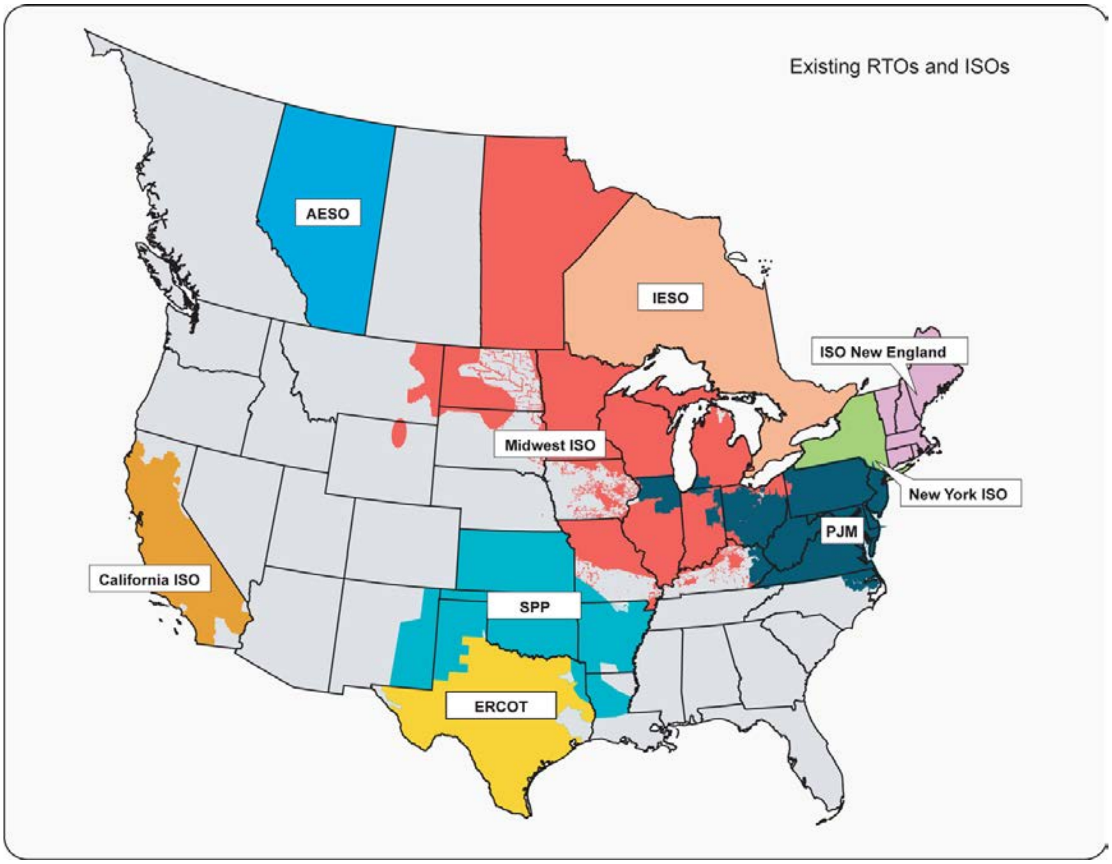
- MISO manages a dispatch area serving 16.5 million customers with a peak load of 112,000 MW, using 132,000 MW of generation resources.

Six of the seven ISOs and RTOs operate centralized wholesale electric markets in conjunction with SCED. In these regions, the key distinction between ISO/RTO economic dispatch and utility dispatch is that in the centralized market, every resource is priced at a bid schedule (prices at different output levels) submitted by its owner or scheduler, rather than from a database of unit-specific variable production costs.

Under fully regulated utility dispatch, utility-owned generators are entered into the bid stack and dispatched according to the marginal production cost of each unit. The capital costs for these power plants are placed in the utility's rate base and recovered – with an opportunity for a return on the investment as well – from native load customers through a wholly separate rate mechanism apart from production costs. Utility-owned generation often bears limited fuel-price risks because fuel costs are reviewed by the state regulator and passed on (in large part) to ratepayers through fuel adjustment cases that are exogenous to the economic dispatch process.

In contrast, NUGs are not rate-based and do not have a wholly separate revenue stream for capital cost recovery. Although economic theory says that in a perfectly competitive wholesale electric market, competing generators will bid their production at its marginal costs, this does not always happen. When a NUG's' bid exceeds its marginal production costs, the excess goes to cover some portion of its capital costs, other fixed costs, and profit. The NUG also bears all risks of fuel price volatility and associated hedging. This means that even though a NUG may be a more efficient power producer than a utility-owned plant on a pure "Btu-in, kWh-out" basis, the NUG's bid may be expensive than the utility plant's production cost.

Figure 2
Map of ISOs and RTOs



Because economic dispatch is designed to minimize the total cost of meeting demand reliably, it will use the lowest-cost resources first. Thus, utility-owned generation, priced at its marginal cost, may be dispatched more often than NUG production. If a NUG wishes to increase its dispatch rate and production, it must lower its bids; the Idaho Public Utility Commission notes that utility purchases of NUG energy through spot-market bids may allow NUGs to recover little of their capital costs.

Within these markets, ISO and RTO conduct SCED, but here too, the details vary. For instance, CAISO (as described by Southern California Edison):

> … operates a limited number of markets including day-ahead and hour-ahead ancillary services and real-time imbalance energy. The ancillary service markets are designed to provide operating reserves to the CAISO and the real-time imbalance energy market is designed … to enable the CAISO to balance energy supply and demand after the hour-ahead market.

> In both cases, the CAISO will dispatch from these markets based upon economic dispatch subject to system constraints. In the Day-Ahead and Hour-Ahead time frame, the CAISO relies on scheduling coordinators to submit a balanced schedule of loads and resources. Thus, scheduling coordinators (of which SCE is one) perform economic dispatch to optimize their own portfolios. These schedules are then subject to redispatch by CAISO due to system limitations or needs (e.g., transmission congestion), changing system conditions (e.g., loss of a generating unit), or economics (e.g., cost savings are achieved by accepting various bids from generators to increase or decrease their output).

The eastern RTOs and ISOs work more with individual resource schedules and have less bulk pre-scheduling than in CAISO and ERCOT. NYISO comments that the "most significant difference distinguishing the NYISO's system from the others is that it fully 'co-optimizes' bids and offers for energy and ancillary services, i.e., regulation and various reserves products, so that the total cost of all these products is as low as possible (consistent with reliability)."

How Large Should a Dispatch Area Be?

The size of a dispatch area matters for two reasons. First, the size of the area managed reflects both history and the scale of the tools and task appropriate to the individual grid manager. Second, the magnitude of the reliability and economic benefits realized from economic dispatch depends upon the size of the area that the integrated dispatch covers.

Survey respondents indicated that the area covered by economic dispatch should:

1) cover a utility's footprint (including the generation dedicated to serving that utility's load),

2) span a combination of loads and transmission and generation resources adequate to meet those loads, or

3) respect natural electricity trading patterns.

South Carolina Electric & Gas represents the small dispatcher's viewpoint, saying, "the fact that an economic dispatch area is small in scale presents no obstacle to effective economic dispatch. The benefits derived from economic dispatch are not determined by geographic area; rather, they are determined by the ability to select among different resources on the basis of cost without compromising system reliability or violating other requirements."

Southern Companies asserts that "areas smaller than approximately ten times the largest generating unit in the dispatch area would be exposed to unacceptable risk from unit trips and failures of other equipment that could impose dispatch step changes greater than can be accommodated by available ramp capacity."

In contrast, PacifiCorp "understands that economic dispatch is optimized when it is coordinated over as large an area as possible, with the participation of as many resource options as possible given transmission constraints."

Several participants expressed caution about the trade-off between the size of the coordination area to gain operational efficiencies and the complexity of the task. One representative caution comes from ISO-NE:

> In general, a larger geographic scale or area (from power system point of view) would produce a bigger benefit due to the savings in market efficiency and economies of scale, but these benefits would have to be weighed against the associated costs…. The complexity, technical challenges and risks will also grow exponentially with the scale of the power system. At a certain level, the operator comprehension during times of emergency, modeling complexity, regulatory complexity, state estimation, and even the supporting computer applications may reach their limits.

All participants agree that SCED captures efficiencies in production, reducing costs to customers. But economic theory suggests that the sum of separate cost-minimizing dispatch solutions for several independent but adjacent dispatch regions is likely to be larger than the cost-minimizing solution that would result if the entire area were combined and dispatched as one integrated system. This is the question of local versus global optimization or minimization. The experience of the northeastern RTOs and ISOs and myriad cost-benefit analyses (discussed in Section 3) show that cost optimization integrated across a larger pool of utilities produces lower total energy costs and greater economic savings from efficiency improvements than parallel dispatch operations. As an operational matter, the larger RTOs report that the bigger the area that SCED covers, the more likely that operational limits can be respected with a solution that melds economics and reliability quickly and effectively. A larger economic dispatch area also allows the dispatcher to take advantage of the load diversity across the area, to better allocate resources to load needs. The "GridWest Rewards and Risks" study, for example, projected $178 million per year in reduced generation production costs from the greater efficiencies that would result from RTO-wide economic dispatch.

The North Carolina Electric Membership Corporation says that in the southeast where dispatch is practiced on an entity-by-entity basis:

> ... the only attempt to optimize the dispatch regionally is through short term sales and purchases. This results in a sub-optimal dispatch on a regional basis. Attempts to optimize dispatch on a daily and hourly basis are further impeded by market rules that impede such short term transactions. The list of rules includes items such as:

- Timing of OASIS [Open Access Same Time Information System] reservations
- Tagging timelines
- Cost of energy imbalance impedes participation
- Energy imbalance versus inadvertent energy
- Lack of firm hourly transmission.

Although there is communication between dispatching entities, reliability can be challenged due to somewhat uncoordinated dispatching decisions.

It should be noted that wholesale electricity cost efficiencies and savings may or may not be passed through to retail customers, depending on whether the state has retail competition and, if traditional regulation is employed, how state regulators handle the utility's rate recovery.

Economic Dispatch and Reliability

Because economic dispatch incorporates security and reliability considerations and constraints, it promotes and improves grid reliability. NYISO observes that using economic dispatch allows the operator to deploy resources more efficiently and thus handle higher peak loads more reliably than would be possible without economic dispatch. PJM comments that economic dispatch, combined with LMPs, makes reliability needs clear and transparent to everyone in the region and the market. Because LMPs are highest where the need for power is greatest, they immediately reflect the impact of grid conditions such as transmission bottlenecks, peak loads, or generating units losses, and create an incentive for every market participant to respond by supplying power (or reducing load) where most needed. No participant suggests that economic dispatch, as currently practiced, might compromise grid reliability.

Nonetheless, several participants express concern that if the definition or practice of economic dispatch were changed to increase use of NUGs, "an overly simplified economic dispatch could put grid reliability in danger." This highlights the importance of assuring that economic dispatch definitions and rules continue to protect and do not inadvertently compromise reliability (although reliability should not be used as a pretext for discrimination). However, several participants believe that greater reliance on non-utility generation can improve reliability. More than one-third of the nation's capacity today is composed of these newer, advanced-technology, high-efficiency plants. Increasing their use could lead to higher unit availability rates, increased capacity to maintain grid reliability, possible improvements in transmission flows, and more low-cost energy and capacity.

SECTION 3

THE BENEFITS OF ECONOMIC DISPATCH

This section looks at the "potential benefits to residential, commercial, and industrial electricity consumers nationally and in each state if economic dispatch procedures were revised to improve the ability of NUGs to offer their output for inclusion in economic dispatch," as directed in EPAct Section 1234.

The assessment is based on a review of recently published studies and responses to the Department's brief questionnaire. The limited time available for this study did not allow the Department to perform new modeling and quantitative analysis specifically of economic dispatch impacts. It is important to bear in mind that most of the materials used for this assessment are not focused solely or even directly on the question of economic dispatch as posed by the Act. This review is not intended to evaluate the methods and assumptions of the studies examined, so the Department's findings are bounded by the studies' methods and assumptions. This review does, however, point out issues that merit attention in future studies.

Congressional Intent and Study Definitions

In assessing the benefits of economic dispatch, the term "benefits" is interpreted narrowly, as defined in EPAct Section 1234, by equating benefits with the direct, net economic savings that result from decreases in the price or cost of electricity to residential, commercial, and industrial customers (both nationally and in each state). Important but less direct or hard-to-measure impacts, e.g., on reliability or the environment, are not included. The studies estimate benefits from increased lower-cost generation and presume that those savings are passed through in retail rates to end-use customers (even though that is not always the case). When it is available, information on the economic costs associated with securing increased dispatch benefits (e.g., the cost of establishing and running an RTO) is noted because the benefits to electricity consumers would be net of these costs.

It is not possible to estimate the benefits of economic dispatch to different customer classes and states based solely on the studies of economic dispatch to date, because few of these studies disaggregated benefits to the level of individual customer classes or individual states. The lack of information reflects the aggregated nature of the regions studied. Equally important, assessing the impacts of dispatch changes on retail customers would require consideration of federal and state ratemaking policies, such as allocation of FTRs and the effects of retail rate freezes. The studies reviewed do not treat these issues consistently.

It is not always clear how the different studies classify non-utility generation. Every study appears to use a common meaning for "utility-owned generation" -- that which has been placed in the rate base for capital-cost recovery within the service area of the dispatching party. However, an off-system (export) sale from one utility-owned power plant into another utility's service area would be considered non-utility generation in the latter's economic dispatch stack. In regions where dispatch is performed by vertically integrated -- yet functionally unbundled -- utilities, this study uses the term "non-utility generator" to include any generation not owned by the party conducting the dispatch; other studies may use NUG to mean merchant generators or IPPs. This lack of consistent definition and focus makes it impossible to tally the impacts of economic dispatch upon NUGs.

Overview of Prior Studies and Other Materials Reviewed

This report examined twenty-five studies and documents, which can be found either in the public domain or among the additional materials submitted to the Department. Full citations of the sources reviewed are listed in Table 3.1. The studies were grouped into three categories:

1) **RTO studies**: Benefit-cost studies of the impacts of recent FERC electricity restructuring policies, notably policies encouraging formation of RTOs in various parts of the country;

2) **IPP studies**: economic dispatch studies prepared by or in response to IPPs seeking to increase production within an existing dispatch footprint (these generally focus on the southeastern U.S.); and

3) **Retail rate studies**: Empirical assessments of retail rates in restructured electricity markets.

This report focuses on the first two types of studies (RTO and IPP studies) because they formulate their study problems explicitly in terms of changes in generation dispatch.[7] Both compare two scenarios of generation dispatch: a base-case scenario that represents the status quo and a change-case scenario that alters assumptions about available generation or the manner in which generation is dispatched. The difference between the two scenarios measures the benefit or impact of the change in generation dispatch.

As noted earlier, the studies do not uniformly report findings either by customer class (i.e., residential, commercial, or industrial) or by state. Thus, to address Congress'

[7] The third type of study, retail rate studies, is not given further consideration in this assessment because the formulation of these studies prevents separation of the impact of changes in generation dispatch from the impact of other changes affecting retail rates. Two studies that fall into this category were identified (Sutherland 2003 and Biewald et al. 2004). These studies examine historic retail rate trends. Because retail rates are affected by many factors in addition to economic dispatch, such as state retail rate policies, it is not possible to isolate the impacts of economic dispatch in these studies.

direction in Section 1234, study findings are summarized with qualifications indicating the extent to which the studies address impacts on customer classes or states.

Review of RTO Studies

The largest body of recent, published work on economic dispatch consists of studies of the prospective benefits and costs of industry restructuring. We reviewed sixteen of these studies. Thirteen of these studies focused on FERC policies encouraging RTO formation. The remaining three studies focused on market redesign within an existing RTO (TCA/KEMA 2004), transmission construction to relieve bottlenecks (CERA 2004, 2004, and 2005), and an assessment of the overall impacts of restructuring (GED 2005).

The principal benefit quantified in these studies is improvement in generation dispatch. For example, the studies on RTO formation focus on the changes that might result from centrally dispatching a large fleet of generation over a broad geographic footprint, compared to the current practice of simultaneous economic dispatch of subsets of this fleet by the entities representing the individual geographic areas within this footprint. Total generation capacity (and its composition) and total demand are held fixed. The main cost that is quantified is that of setting up and operating either an ISO or RTO.

Table 3.2 summarizes the quantitative findings from RTO studies. RTO studies have found economic dispatch benefits ranging from $80 million to over $40 billion, depending on the region and length of time studied. Normalized, these benefits range from one to five percent of total wholesale electricity costs.

Improvements in generation dispatch tend to be driven by three factors. First, some savings result from substitution of lower-cost fuel (e.g., coal) for higher-cost (e.g., natural gas) fuel. This result is prominent in studies of areas in the Midwest. Second, some savings result from substitution of more-efficient generation (low heat rate) for less-efficient generation (high heat rate), both relying on the same fuel (typically natural gas). This result is prominent in studies of the Northeast. Third, some savings result from reductions in or even elimination of trading costs (called "hurdle" rates) between existing sub-regions. This effect is considered by all of the studies reviewed.

Production cost simulation methods are used to analyze the economic dispatch benefits treated in RTO studies. Production cost simulation is a mature technology that has long been used by utilities for assessing generation and transmission expansion plans. These tools seek to replicate generation dispatch procedures by determining the total variable cost of serving a fixed set of loads with a fleet of generating units. Advanced uses of these tools can take into account many important aspects of generation dispatch, including scheduled and unscheduled forced outages by generators, ramping constraints and unit commitment, hydro generation scheduling, and reliability issues in the form of transmission constraints. However, because production cost simulation models were developed originally to support planning studies, they often necessarily simplify or suppress aspects of actual dispatch procedures.

Eto, Lesieutre, and Hale (2005) reviewed many of the earlier RTO studies examined in this assessment. Several findings from that review are relevant here:

- Improvements in economic dispatch may not be most important impact of FERC's restructuring policies. The effects of FERC's policies on reliability management, generation and transmission investment, and wholesale market operations have not been treated systematically or comprehensively in the recent studies, and therefore may have been underestimated.

- Presentation of results in prior studies may be piecemeal or highly aggregated. This sometimes precludes assessments of the impacts on consumers versus producers or among all sub-regions affected by changes in dispatch. In addition, important regulatory policy considerations, such as assignment of FTRs, are sometimes not within the scope of the studies, which prevents them from assessing the final impact of changes in dispatch on retail rates.

- Because the principal economic benefit under analysis is improved dispatch over a larger geographic footprint, the results are affected by: specification of hurdle rates in the base case (and the rationale for changes to these rates in the change case), model calibration for the base case, treatment of bidding behavior by market participants, and the representation of the area's transmission capability.

Review of IPP studies

EPAct Section 1234 directs DOE to examine the "potential benefits … if economic dispatch procedures were revised to improve the ability of non-utility generation resources to offer their output for inclusion in economic dispatch." Because economic dispatch is currently practiced in some form throughout North America's bulk power industry, this directive is interpreted as referring to the impact of potential increases in NUG electricity production as a result of either changes in current generation dispatch practices or changes in the rules by which NUGs can participate in the dispatch stack.

To suggest that additional benefits might accrue from changing current practices presumes both that lower-cost (e.g., non-utility) generation is available and that this generation is currently being under-dispatched. The assumption is that if lower-cost generation were both available and dispatched more frequently than is currently the case, total dispatch costs would be lower, which would lead to lower electricity costs. IPP studies start with this assumption and ask how much more NUG generation could be dispatched and what production cost savings would result.

Seven studies examine replacement of some amount of generation from an existing fleet with increased generation from IPPs. In each of these studies, the geographic footprint of the area dispatched and the demand served are held fixed. In the change-case scenario, the total generation capacity available to serve demand is increased by the additional generation capacity from the IPPs.[8] Thus, IPP studies increase the total amount of generation capacity available for dispatch to a fixed set of loads; in contrast, RTO studies hold both generation capacity and loads fixed.

The basic formulation of the IPP study problem is as follows:

> The economic impact of increased generation by IPPs
> *equals*
> [The amount of existing generation displaced or replaced by new generation
> *multiplied by*
> The cost of fuel (assumed to be roughly the same for existing and new generation)
> *multiplied by*
> The heat rate differential, which equals (the higher heat rate of less efficient, displaced existing generation *minus* the lower heat rate of the more efficient, replacement new generation)].

Table 3.3 summarizes the quantitative findings from the IPP studies. IPP studies have found economic dispatch benefits ranging from $30 million to over $900 million, depending on the region and length of time studied. Normalized, these benefits range from eight to more than thirty percent of total variable production costs.

Because the marginal fuel used in both dispatch scenarios is generally assumed to be the same (i.e., natural gas), changes in dispatch are driven primarily by differences in generation efficiency between the two fleets. Table 3.3 summarizes these differences in terms of the heat rates assumed for the two fleets of generation (for the studies that provided this supporting information).

The methods used to calculate these impacts range from simple spreadsheet-type examples to production cost simulations. As noted above, production cost simulations can in principle account for many of the factors influencing the generation dispatch by system operators. Spreadsheet approaches are more limited than production cost simulations in their ability to account for these factors.

The realism of IPP studies depends on how several elements are handled, including calibration of the base case and representation of the physical, market, and regulatory factors that may constrain dispatch of lower variable cost generation. In addition to the considerations discussed in reviewing the RTO studies, these factors also include treatment of bilateral contracts (including QF contracts), calculation and posting of available transmission capability (ATC), implementation of reliability requirements, handling and allocation of financial transmission rights (FTRs) and congestion costs, and whether and how potential production cost savings are passed through in retail rates.

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[8] One study (Entergy 2004a) examines transmission expansion in order to enable greater dispatch of merchant generation.

Findings from Review of Prior Studies and Submitted Materials

Studies that evaluate the potential for benefits from changes to current economic dispatch practices fall into two categories -- studies of the impact of FERC policies and studies of the impact of increased dispatch of IPPs. These two types of studies were not designed to present comprehensive information on economic dispatch benefits disaggregated by geographic region and customer class, as envisioned by Section 1234.

Only two of the studies reviewed were national in scope. One focused on the impacts of FERC Order 888, and the other focused on the impacts of SMD; neither was focused primarily on the issue of economic dispatch. The remaining studies focused on specific regions or dispatch areas. The time frames and study problems of each varied, sometimes considerably, depending on the study objective. Thus, it is impossible to extrapolate from these documents a consistently defined nationwide or regional estimate of the impacts of economic dispatch.

Most of these studies focused on changes in wholesale electricity costs. Assessing the impacts of changes in economic dispatch procedures on retail customers requires consideration of federal and state ratemaking policies, such as allocation of FTRs and the effects of rate freezes. As a group, the studies reviewed did not treat these issues consistently.

RTO studies compare centralized dispatch of a large portfolio of generating units (both utility-owned and non-utility owned) aggregated over multiple control areas to the current practice of simultaneous, independent dispatch of subsets of this portfolio by individual control areas. RTO studies have found economic dispatch benefits ranging from $80 million to over $40 billion, depending on the region and length of time studied. Normalized, these benefits range from one to five percent of total wholesale electricity costs.

The somewhat modest dispatch savings found by RTO studies (compared to the savings found by IPP studies) is consistent with the formulation of the study problem. That is, in the base case, individual control areas are assumed to dispatch the generation they control in order to minimize the total variable cost of production. Aggregating these control areas and redispatching the same fleet of generation to meet the same loads can reduce cost only if there are opportunities for additional cost-reducing, inter-control-area trade. Thus, the specification of hurdle rates, which are used to represent trading “friction” among control areas in the base case and which are lowered or eliminated in the change case, is extremely important.

IPP studies compare dispatch of a combined fleet of new (typically non-utility-owned) and existing (typically primarily utility-owned) generating units within a single control area to the current practice of dispatching existing generating units. IPP studies have found economic dispatch benefits ranging from $30 million to over $900 million, depending on the region and length of time studied. Normalized, these benefits range from eight to more than thirty percent of total variable production cost.

The percentage cost reductions found by IPP studies is consistent with the formulation of the study problem. The change case includes additional, highly efficient generation capacity from IPPs, and the redispatch in the change case results in increased generation by these units to displace generation by older, less efficient units in the base case.

Both types of studies rely, for the most part, on production cost simulation methods, which seek to replicate least-cost dispatch of a specified fleet of generation. However, modeling practices vary, and the methods used are sometimes limited in their ability to evaluate all aspects of actual dispatch procedures.

If production cost simulation models are used in the future to study the impacts and benefits of changes in dispatch procedures, the analysts will have to pay particular attention to handling the following issues:

- Representation of bilateral contracts (including QF contracts)
- Calculation and posting of ATC
- Bidding behavior by participants in wholesale markets
- Reliability requirements
- Fuel diversity requirements
- Hydrological and environmental constraints
- Handling and allocation of FTRs and congestion costs
- Whether and how potential production cost savings are passed through in retail rates.

Table 1 – Studies and Documents Reviewed to Assess Benefits of Economic Dispatch

Study Author ***Study Title***	**Date**	**Study Type**
Pennsylvania, New Jersey, Maryland Interconnection (PJM). *Northeast Regional RTO Proposal Analysis of Impact on Spot Energy Prices*.	2002	RTO
ICF Consulting. *Economic Assessment of RTO Policy*.	2002	RTO
Tabors, Caramanis, and Associates (TCA). *RTO West Benefit/Cost Study*.	2002	RTO
Energy Security Analysis, Inc (ESAI). *Impact of the Creation of a Single MISO-PJM-SPP Power Market*.	2002	RTO
Independent System Operator-New England (ISO-NE), New York Independent System Operator (NYISO). *Economic and Reliability Assessment of a Northeastern RTO*.	2002	RTO
Charles Rivers Associates (CRA). *The Benefits and Costs of Regional Transmission Organizations and Standard Market Design in the Southeast*.	2002	RTO
U.S. Department of Energy (DOE). *Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design*.	2003	RTO
Cambridge Energy Research Associates (CERA). *Economic Assessment of American Electric Power's Participation in PJM*.	2003	RTO
Science Applications International Corporation (SAIC). *The Benefits and Costs of Wisconsin Utilities Participating in Midwest ISO Energy Markets.*	2004	RTO
CRA. *The Benefits and Costs of Dominion Virginia Power Joining PJM*.	2004	RTO
Henwood Energy Services, Inc. *Study of Costs, Benefits and Alternatives to Grid West*.	2004	RTO
TCA/KEMA. *Electric Reliability Council Of Texas, Market Restructuring Cost-Benefit Analysis*.	2004	RTO
CERA. *Grounded in Reality: Bottlenecks and Investment Needs of the North American Electric Transmission System.*	2004 2004 2005	RTO
CRA. *Southwest Power Pool, Cost-Benefit Analysis*.	2005	RTO
Global Energy Decisions (GED). *Putting Competitive Power Markets to the Test.*	2005	RTO
GridWest Risk/Reward Workgroup. *The Estimated Benefits of Grid West*.	2005	RTO
Dismukes, D., D. Mesyanzhinov, J. Burke, E. Downer	2003	IPP

The Power of Generation: Continued Economic Benefits from Independent Power Development in Louisiana.		
TECO Power Services. *Study on Benefits of IPP Generation to Entergy Consumers*.	2003	IPP
Tractabel North America. *Electric Competition in the States of Arkansas, Louisiana, and Mississippi – Is there an Opportunity?*	2004	IPP
Entergy. *Phase II. Transmission Study Report.*	2004	IPP
Entergy. *Transmission Pricing and ICT Benefits.*	2004	IPP
J. Kennedy Associates and Exeter Associates. *The LPSC Staff Retirement Study, Updated Draft Report for Comment.*	2005	IPP
Brubaker and Associates. *Entergy Oil/Gas Generation vs. Market Purchases.*	2005	IPP
Sutherland, R. *Estimating the Benefits of Restructuring Electricity Markets, An Application to the PJM Region*.	2003	Retail Rate
Biewald, B., W. Steinhurst, D. White, A. Roschel. *Electricity Prices in PJM: A Comparison of Wholesale Power Costs in the PJM Market to Indexed Generation Service Costs*.	2004	Retail Rate

Table 2 - Summary of Economic Dispatch Benefits from RTO Studies

Study	Geographic Scope	Aggregate Benefits	Benefit Type (% of base case, if available)	Additional, Disaggregated Perspectives Also Presented
PJM 2002	PJM, NYISO, and ISO-NE	$300M/yr	Reduction in load payments (2%)	PJM, NYISO, ISO-NE Production cost and revenue changes
ICF 2002	National	$41B	20 year net present value in reduced wholesale generation costs (4%)	12 regions
TCA 2002	WECC	$300M/yr	Difference between load payment reductions and generator net revenue reductions	Subregions, WECC Consumer and producer impacts
ESAI 2002	MISO, PJM, SPP	$7.0B	Price of energy over 10 years (~3%)	None
ISO-NE/ NYISO 2002	ISO-NE and NYISO	$220M/yr in 2005 and $150M/yr in 2010	Wholesale power costs (3% declining to 2%)	ISO-NE and NYISO
CRA 2002	Eastern Interconnection	$2.1B	Present value of reduced generator payments + merchant generator net benefits 2004-2013 (<1%)	GridSouth, SeTrans, GridFlorida, Eastern Interconnection Consumer and producer impacts
DOE 2003	National	$1.8B/yr to $1.5B/yr	Wholesale electricity costs (both <1%)	12 regions
CERA 2003	PJM combined with AEP	$245M in 2004 declining to $188M in 2008	Wholesale energy costs	PJM and DVP, individually
SAIC 2004	MISO	$105M/yr	Reduced generation costs plus off-system sales and FTR revenue (~8%)	Wisconsin utilities Consumer and producer impacts
CRA 2004	PJM combined with DVP	$800M	Total energy plus capacity and ancillary services savings over 10 yrs	None
Henwood 2004	RTO West	$78M/yr	Pancaked wheeling rates, operating reserve cost savings, and transmission asset utilization	None
TCA/ KEMA 2004	ERCOT	$586M	NPV of generation cost reductions from 2005-2014 (-0.2% to +1.2%/yr)	Impacts on TX subregions
CERA 2004	Eastern, Western Interconnection	East $28-136M/yr West $18-64M/yr	Net generation cost savings in 2010 or 2015 under low and high gas price assumptions	Generator margin and load savings by sub-region, assuming LMP pricing

2005	and ERCOT	ERCOT $6M/yr	(Eastern and Western Interconnection); 2010 (ERCOT)	
CRA 2005	SPP	$614M	Production cost savings 2006-2015 (2.5%)	Impacts on firms, and states
GED 2005	Eastern Interconnection	$15.1B	Reductions in total operating expenses from 1999-2003 (7%)	PJM, individually
GridWest2005	GridWest	$144 to $458M/yr	Cost savings in contingency and regulating reserves, redispatch efficiencies, rate pancaking, and reconfiguration- transmission utilization	4 control areas vs. 10 control areas

Table 3 - Summary of Economic Dispatch Benefits from IPP Studies

	Economic Dispatch Benefits (% of base case)	Study Type	Displaced Generation Heat Rate	Replacement Generation Heat Rate	Nat. Gas Cost	Notes
Dismukes, et al. 2003.	Regional prod. cost savings 2000: $411M (15%) 2003: $825M (~30%); 2005: $926M (~33%)	Spreadsheet	Varies by unit	Varies by unit	N/A	Savings are the difference between two supply curves
TECO. 2003.	Production cost savings 2003-2007: $923M (8-9%)	Production cost simulation	Varies by unit	Varies by unit	N/A	
Tractabel. 2004.	Fuel savings: $610M/yr Fixed O&M savings: $280M/yr	Spreadsheet	11375 Btu/kWh	7000 Btu/kWh	$6/MBtu	Separate results for AR, LA, MS
Entergy. 2004a	$128-311M in net savings over 2004-2026	Production cost simulation	Varies by unit	Varies by unit	N/A	Net savings from seven transmission projects
Entergy. 2004b.	$30M/yr for every 1% reduction in oil/gas generation	Unknown	N/A	N/A	N/A	From Entergy presentation
Kennedy and Exeter. 2005.	$-54M-32M/yr average (2006-2012) considering retirement of Entergy units and replacement with both new Entergy units and merchant generation	Production cost simulation	Varies by unit	Varies by unit: 7700-8500 Btu/kWh	$6.4 –5.1 /MBtu	Savings are net of fixed cost of new utility-owned units
Brubaker. 2005.	Cost savings from market purchase 2004: $214M 2005: $146M (first 7 mo)	Spreadsheet	2004: 73.6 mills 2005: 85.9 mills	2004: 42.0 mills 2005: 45.7 mills	N/A	Comparison of actual gen. and market purchases

SECTION 4

WHICH RESOURCES GET INTO THE DISPATCH STACK?

Economic dispatch (including both SCED and SCUC) is a complex but relatively mechanical process that should identify a set of resources to be dispatched to meet electricity loads and should meet demand at the lowest cost given the available resources and prevailing grid conditions at the time. Section 2 above addresses two issues that could reduce a NUG's chances of being dispatched -- if the NUG's bid price exceeds the utility-owned generator's marginal production cost, or if the dispatching entity needs certain reliability-related services or has certain reliability or operational requirements that the NUG is not contractually or physically able to provide or meet.

The Electric Power Supply Association (EPSA) notes that across the U.S. there are 55,920 MW of non-utility generation that are listed as uncommitted resources, i.e., are available but have no bilateral forward contracts with utilities or firm transmission service.[9] EPSA asserts that, particularly within the Southeast Electric Reliability Council and the Southwest Power Pool (both regions where integrated utilities manage economic dispatch), new, highly fuel-efficient NUGs are under-utilized and sit idle while older, less efficient utility-owned plants run. EPSA contends that in the absence of a formal contract with a NUG, the utility dispatcher will dispatch its own generation first and then fill in with the non-utility generation "on an as-needed basis."

NUG complaints about economic dispatch revolve around allegations that vertically integrated utilities use their dispatch processes to favor utility-owned generation over non-utility-owned generation. NUGs point to several practices by vertically integrated utilities as indicating this bias:

1) Practices that limit the consideration of NUG resources within the economic dispatch stack,

2) Practices that limit NUGs' ability to sell their power to the dispatching utility or to off-system buyers,

3) Utilities' unwillingness to consider electricity offered by NUGs, and

4) Inadequate information on and transparency of the details of utility dispatch procedures and whether these procedures are being fairly administered.

Utilities respond that:

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[9] This designation of uncommitted resources is found in NERC's 2005 Long-Term Reliability Assessment.

1) They are using appropriate economic dispatch procedures mandated and overseen by their state regulators or governing boards/authorities.

2) Under these procedures, total production costs are minimized, subject to the aforementioned constraints, such that cost-minimizing economic dispatch will not always call on NUG units even when the short-run variable costs of NUG units may be low.

3) NUGs don't offer all of the services provided by utility-owned generation (such as regulation, load following, operating reserves, and voltage support) and thus cannot be incorporated into dispatch processes as equals to utility-owned generation.

Section 1234 of EPAct[10] directs the Department to identify changes in economic dispatch procedure that would improve the ability of NUGs to participate in economic dispatch.[11] As Section 3 illustrates, economic dispatch procedures are neutral and will dispatch whatever available resources satisfy specific requirements and constraints in the most economic way. Virtually every survey respondent to the Department's survey offers the view that economic dispatch should not distinguish between utility and non-utility generation. Therefore, the challenge is not to modify economic dispatch procedures *per se* but to look at two related issues – whether constraints that frame the economic dispatch system inappropriately favor or harm NUGs, and whether NUGs (and other resources) are recognized as available for dispatch consideration.

If a resource is considered to be available, it will be included in the economic dispatch resource stack and will be dispatched if its cost is competitive with other resources or if its output is needed to satisfy reliability concerns. But if it is not in the stack, it cannot be dispatched.

The alleged rationale for an integrated utility to discriminate against a NUG in the dispatch process is as follows: because the utility owns generation (for which it receives return of and on its investment, plus a fuel cost pass-through), it wants to run its own generation rather than lose sales to another supplier (whether an NUG from within the system or an import from outside the system). The dispatching utility can use its control over transmission service availability and economic dispatch processes to protect its own generation and hinder competing resources. Although several complaints have been filed alleging such conduct by various dispatching utilities, few have been conclusively proven.

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[10] The same mandate also appears in Sec. 1832.

[11] The language of the statute ("improve the ability of non-utility generation resources to offer their output for sale for the purpose of inclusion in economic dispatch") can be interpreted in two ways: either it refers broadly to increased sales by NUGs or narrowly to increased dispatch of NUGs. This section uses the latter interpretation; however, in many cases this can only be achieved by making the NUG fully dispatchable under the direct control of the dispatcher.

This section briefly reviews various conditions under which a resource might be affected by the specification of economic dispatch constraints or might not be included in the economic dispatch resource stack. In listing these conditions, this report takes no position on whether such events are occurring in specific areas or result from the practices of any particular dispatching entity. Some of these conditions or practices have been alleged to be violations of the prohibition against "undue prejudice or disadvantage" within interstate power markets [16 USC 824(d)] and may be under past or current non-public investigation at FERC.

Conditions that Could Exclude a Resource from the Dispatch Stack

Qualifications for transmission service, such as firm contracts to serve network loads. A generator that has a firm contract with a buyer will be dispatched (if it has a transmission contract and does not require a reliability redispatch). Utility-owned, rate-based generation generally has an explicit arrangement to serve network (native) loads. If a dispatcher excludes from the dispatch stack any generator that does not have such a contract, a NUG would not be allowed to compete within the resource stack.

Calculation of Available Transmission Capability (ATC) or Total Transmission Capability (TTC) in ways that reduce the amount of transmission available to competing resources. TTC is the amount of electric power that can be transferred reliably over the interconnected transmission network. ATC is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses; it is calculated as TTC minus existing transmission commitments (such as those to retail customers), less a margin to protect load-serving entities' ability to import power in the emergency event that they lose local generation needed to serve retail customers, less an additional margin to provide flexibility in the event of changes in transmission system conditions (NERC 2005).

TTC and ATC are calculated by the dispatcher using information about grid flow capabilities and loadings that may be proprietary (and thus not transparent to outside parties). Some dispatchers use calculation methods and assumptions that are not shared with all of the resources using the transmission system; this lack of transparency invites questions about the accuracy and objectivity of the calculations. Beyond the issue of whether the calculations are correct and unbiased, there have been situations where utilities have posted inaccurate ATCs.[12]

Reserving transmission capacity (ATC) for native load and network customers. The economic dispatch process seeks to match production from generation to the loads within the dispatch service area. Some integrated utility dispatchers will allocate transmission

[12] For instance, a 2004 FERC audit found significant errors in Entergy's use of the methodology, including erroneous calculations and inadequately documented Transmission Service Requests that led to inaccurate estimates of ATC (now called Available Flowgate Capacity within Entergy).

capacity first to deliveries to native load or network customers and make the residual capacity available for other transmission flows. If there is no remaining ATC available for a NUG to use to deliver to native load customers, then the NUG is eliminated before it ever gets into the dispatch process. This can be a circular problem; the NUG may not be able to get contracts without transmission access and may not be able to get transmission access without contracts.

Suez Energy North America reports that a dispatching utility may lock up and hold onto transmission capacity for its own generation to preclude merchant generation from selling to other buyers, but later modifies the dispatch order to reduce its own generation and pick up the merchant generator's production at a lower cost.

A related problem may be whether the NUG can get transmission service to sell its output to a neighboring area if it is not selling in the host dispatch region. Without transmission access, the NUG may not be able to deliver power to another region, either for contracted off-system sales or to compete in its economic dispatch stack.

<u>Special requirements for provision of ancillary services</u>. If the dispatcher requires that dispatchable units have must have regulation capability, automatic voltage control capability, or must meet particular standards for unit excitation systems, a NUG unit that does not offer these features might be excluded from the dispatch stack even if the generator's contract does not call for these capabilities.

<u>Persistent displacement by OOM[13] resource</u>s. If the dispatching entity repeatedly determines that a reliability problem requires that an OOM resource be employed, and the OOM resource blocks sustained deliverability from the interrupted generator to that generator's load, the blocked generator may lose its sales opportunities and its customers will lose access to lower-cost energy.

<u>The configuration of the existing transmission system</u>. The existing transmission system's configuration limits the ability of dispatchers to accommodate additional generation from units located in certain transmission-constrained locations within the system. In many cases, expanded transmission capacity will increase the deliverability of output from efficient generators to loads. But in many areas there are delays in building new transmission capacity that would reduce congestion and enable greater transmission flows.

<u>Requirement to share proprietary generator data.</u> These data are needed for accurate, effective dispatch modeling. Although NUGs are willing to share these data with an

[13] Out of merit order dispatch refers to changes in the dispatch that occur in real-time after the dispatch stack has been selected. In real-time, unplanned contingencies or the cumulative effect of schedules implemented by neighboring systems may necessitate re-dispatch of existing resources "out of merit" order, such that higher cost resources are sometimes dispatched in place of lower cost resources."

independent market operator (such as an ISO or RTO) that has an obligation and protocols to keep the data confidential, many NUGs feel differently about sharing with a dispatcher that owns competing generation. NUGs claim that if they disclose proprietary business data about the costs and operational capabilities of their units, the utility can use this information to disadvantage the NUG units and favor its own generation by changing the cost curves of utility-affiliated generation to undercut NUG capacity in the dispatch stack or by using its control of transmission service to allocate available capacity to utility-affiliated flows rather than NUG transactions. This is a code of conduct issue that can have a negative impact on economic dispatch.

Although the above issues are relevant to NUGs, similar concerns have been voiced by other non-utility resources, including renewable-energy producers and demand response.

SECTION 5

PROPOSED MODIFICATIONS TO ECONOMIC DISPATCH AND SUGGESTIONS FOR FUTURE WORK

Section 1234 of EPAct directs the Department to recommend legislative or regulatory changes that may be needed to improve economic dispatch and the use of NUGs as part of economic dispatch. This section lists a number of suggestions offered in responses to the Department's economic dispatch survey, along with suggestions for future work. Some of these suggestions are for FERC, which is working with state regulators in FERC-State Joint Boards considering economic dispatch, and reexamining Order 888 on open transmission access. Other recommendations are for the Department or other analysts doing future work on economic dispatch.

Proposals for Modifying Economic Dispatch

Respondents to the survey for this study offered a number of comments and suggestions for modifying economic dispatch to increase cost minimization. This section reviews several of those suggestions. Common themes are ways to improve the transparency of economic dispatch – both the process and outcome – and increase ways for NUGs to be included in that dispatch.

Addressing the definition of economic dispatch given in Section 1234, a majority of survey respondents caution that economic dispatch should not just seek economic optimization, but should try to ensure reliable system operations at the lowest cost possible. Several respondents suggest that reliability will be better served by referring to "security constraints" rather than "operating limits," because the latter is a narrower concept.

All the ISO/RTOs comment that their dispatch is owner-neutral and does not distinguish between NUGs and other resources (several try to be even-handed between generation and demand resources as well). Therefore, they contend that no economic dispatch changes are needed to increase NUG participation. Many of the dispatching utilities express a similar view.

Calpine recommends that all utilities be required to establish an all-inclusive daily dispatch order that incorporates every resource interconnected to their systems, and then dispatches the lower-cost units first (subject to explicit reliability and security requirements). Similarly, EPSA proposes that in non-RTO/ISO regions there should be a mandate that all available and eligible generation will be considered for merit-order dispatch, and that regulators should demand explanations when a utility dispatches the generation it owns in lieu of less expensive resources.

EPSA suggests that utilities should be encouraged to purchase from IPPs using forward bilateral contracts as part of the procurement process rather than looking to NUGs largely for spot-market purchases. This would lead to increased use of NUGs and greater inclusion of NUGs in the bilateral rather than competitive segment of the economic dispatch curve.

Several participants emphasize the importance of having an independent entity with no generation interests – or even an entity separated from all other vertically integrated utility functions, to eliminate all potential conflicts of interest – perform economic dispatch, to assure an objective outcome that does not favor any particular group of resources. Among other things, this entity should have strict requirements for the confidentiality of the proprietary production information used in the economic dispatch process.

If a generator is included in the dispatch stack, the presumption is that the generator can deliver its production to loads; otherwise, the unit cannot be dispatched. Transmission adequacy affects how much generation can flow and how much grid reliability concerns will constrain different generation production and deliverability patterns. Easing key transmission constraints improves access to load for almost every generator as well as improving grid reliability. Therefore, many respondents reiterate the importance of enhanced transmission planning processes that address long-term economics as well as reliability, and of building a more robust transmission network that will enable customers to save money by reliably accessing more efficient generation than is possible with today's transmission system. One NUG recommends that every transmission upgrade that enables access to low-cost generation resources should be built if the upgrade's cost is less than the savings achievable by the dispatch of the lower-cost supply.

Whatever the state of the transmission grid, generators' production and contracting options are limited unless they can get transmission service for their products. Therefore, a number of participants assert that federal and state regulators must reinforce open access transmission rules and outcomes. Where there is no independent entity administering open transmission access, regulators should prevent practices such as "transmission delisting," in which a utility reserves transmission capacity for self-generation until the last minute but then "delists" the self-generation block in order to purchase less-expensive NUG power under a short-term contract.

The Arkansas Public Service Commission notes that there is a need for more transparent determinations of Available Flowgate Capacity (or ATC) than are currently offered. This information would allow market participants and regulators to understand and trust a dispatching utility's statements about whether particular transactions can safely flow across the grid.

A few respondents recommend that the resources considered under economic dispatch should include demand-side resources (such as emergency and market-oriented demand response), and that the Section 1234 definition of economic dispatch should be changed accordingly.

Many respondents caution that it would be a mistake to mandate the use of a specific economic dispatch definition or method throughout the U.S. electricity industry. Some respondents recommend that economic dispatch should be used to employ energy-efficient generation more extensively, and one suggests modifying economic dispatch specifically to maximize the use of cogeneration. However, others fear that this would "create a new class of out-of-economic-merit-order dispatch," leading to energy cost increases. Although many participants note that customers would benefit if increased NUG generation results from increased dispatch of least-cost resources, others warn that a formal mandate could have unintended consequences by compromising reliable operations in favor of pursuing cost savings.

The Edison Electric Institute and several utilities recommend that if a NUG wants to be included in a utility's economic dispatch queue, that generator must commit to provide its energy (and in some instances supporting ancillary services or other desirable unit commitment properties) at the specified price for a specified period of time, to meet the unit commitment schedule. Furthermore, they recommend that all suppliers in the queue should face contractual performance standards with penalties for failure to deliver. Presumably, these suggested requirements (and others such as the ability to follow AGC and provide other ancillary services such as voltage control) can be handled through contract revisions with appropriate compensation. On the same point, EPSA proposes that the industry develop technical protocols for placing and accepting supply offers, operational requirements, non-performance penalties, and standard contract forms to support these routine transactions.

Several participants recommend greater sharing of reliability and operations information among dispatching entities. A complementary suggestion is to enhance economic dispatch by coordinating and optimizing economic dispatch decisions between adjacent control areas. The National Rural Electric Cooperative Association adds that, "greater planning and coordination across control areas is a concern to cooperatives that have load and/or resources embedded in multiple control areas."

Although meeting load reliably is the fundamental goal of economic dispatch, load forecasting is an unappreciated element of the dispatch challenge. Improving the quality of load forecasting will lead to improvements in both the reliability and cost-minimization impacts of economic dispatch.

Recommendations for Future Work

DOE and FERC should explore the EPSA and Edison Electric Institute proposals for more standard contract terms and conditions for NUG-to-buyer contracting and should encourage stakeholders to undertake these efforts, which should benefit the entire wholesale electric industry and its customers.

This study asked briefly about the economic dispatch methods in use, but did not receive detailed, easily comparable information about SCED, SCUC, and their implementation by different entities and areas. As discussed in Section 2, economic dispatch outcomes are affected by which entities administer the dispatch and how each interprets and executes its responsibilities. These questions deserve further study, which could be performed by the FERC-State Joint Boards established under new Section 223(b) and 209(a) of the Federal Power Act. The FERC-State Joint Boards should consider conducting in-depth reviews of selected dispatch entities, including some investor-owned utilities, federal power agencies, ISOs, and RTOs, to determine how they conduct economic dispatch. These reviews could document the rationale for all deviations from pure least-cost, merit-order dispatch, in terms of procurement, unit commitment and real-time dispatch. Entity-specific and regional business practices should be distinguished from regulatory, environmental, and reliability-driven constraints. These reviews, and FERC's ongoing reexamination of Order 888, should be alert for potential discrimination within economic dispatch or exclusion of qualified resources from dispatch opportunities (as discussed in Section 4). Although it is not clear that uniform economic dispatch rules and practices are needed across all dispatching entities, FERC and the states may need to rethink existing rules or craft new rules and procedures to allow NUGs and other resources to compete effectively and contribute to meeting customers' loads economically and reliably.

Several utilities indicated that they do not dispatch NUGs often because the utilities need instantaneous load-following regulation service under AGC, and the NUGs are incapable of providing such service or are unwilling to give up unit control to automatic dispatch. Entergy comments that "IPPs must be required to follow operating instructions with the same level of precision as Entergy's generating units (e.g., respond to AGC signals and comply with voltage schedules) if they are [to be] dispatched in lieu of Entergy's own units with AGC." The NUGs, in contrast, say they provide exactly the services that their contracts call for, and that few contract negotiations have requested or been willing to pay for AGC or other ancillary services features. The issue of NUG capabilities and willingness to provide such features with proper assurances and reliability – and the degree to which the dispatching entity needs them from every NUG – deserves further study.

NUGs suggest that a study is needed to look at non-ISO/RTO areas and examine real-time historical data about actual unit cost and schedule offers in comparison with actual dispatch patterns to determine whether NUG and utility-owned generation were truly dispatched in an unbiased fashion or whether more NUG production could have been dispatched (within the prevailing system conditions), producing greater savings for customers. The required data sets would have to be obtained from control areas under federal promise of confidentiality and data protection.

One industry observer proposes a study of areas that perform bid-based economic dispatch within real-time markets, to compare the market-clearing price outcomes and total costs against the true production costs of the actual units dispatched. This study would presumably examine two questions: how NUG bids in regulated utility dispatch (and utility-owned generator bids in centralized markets) compare to actual production costs, and how total electricity costs in centralized markets compare to total costs in the of the same production priced at its actual production cost. Such a study would require significant data or assumptions, incorporating energy costs and line losses within economic dispatch. It would have to recognize that a significant amount of the total energy consumed within a region comes from utility-owned generation and bilateral contracts that are not priced at the MCP. In addition, the study would need to incorporate ratepayer charges for capacity for utility rate-based plants and stranded cost recovery, any payments made under a market-capacity-revenue scheme, and acknowledge any savings that might accrue to ratepayers for NUG capital costs left unrecovered from an energy-only revenue stream.

Given the diversity of size and scope of the dispatch areas now operating across the nation and the need for economic dispatch to continue to produce affordable, reliable outcomes, the technical quality of current economic dispatch technology tools – software, data, algorithms, and assumptions – deserves scrutiny. Any enhancements to these tools, including identification and elimination of any resource biases in the calculation methods, will improve the reliability and affordability of the nation's electricity supplies.

As Section 3 discusses, the analyses of economic dispatch impacts that have been conducted to date do not fully address Congress' charge in Section 1234. These studies ask questions that are different from those itemized in the legislation and use analytical models and assumptions that are not wholly appropriate to answer Congress' questions. It would be useful to improve both the modeling and availability of data before attempting a new study to answer the questions specified in EPAct about the impacts of economic dispatch on different regions and customer classes across the U.S. DOE plans to address these matters in next year's report to Congress on economic dispatch.

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APPENDIX A

U.S. DEPARTMENT OF ENERGY SURVEY AND SAMPLE LETTER

Energy Policy Act of 2005, Section 1234
Economic Dispatch Study
Questions for Stakeholders

Section 1234 of the Energy Policy Act defines economic dispatch as "the operation of generation facilities to produce energy at the lowest cost to reliably serve customers, recognizing any operational limits of generation and transmission facilities." With that definition in mind, please answer as many of the following questions as you wish, attaching supporting materials such as studies or testimony that was filed in state or federal regulatory proceedings to support your answer.

Please send your response by e-mail to Economic.Dispatch@hq.doe.gov **no later than September 21, 2005**. Be sure to include the name and phone number of an individual who can answer any questions that may arise about your comments. Thanks in advance for your assistance with this study.

Alison Silverstein alisonsilverstein@mac.com
Joe Eto jheto@lbl.gov

Questions

1) What are the procedures now used in your region for economic dispatch? Who is performing the dispatch (a utility, an ISO or RTO, or other) and over how large an area (geographic scope, MW load, MW generation resources, number of retail customers within the dispatch area)?

2) Is the Act's definition of economic dispatch (see above) appropriate? Over what geographic scale or area should economic dispatch be practiced? Besides cost and reliability, are there any other factors or considerations that should be considered in economic dispatch, and why?

3) How do economic dispatch procedures differ for different classes of generation, including utility-owned versus non-utility generation? Do actual operational practices differ from the formal procedures required under tariff or federal or state rules, or from the economic dispatch definition above? If there is a difference, please indicate what the difference is, how often this occurs, and its impacts upon non-utility generation and upon retail electricity users. If you have specific analyses or studies that document your position, please provide them.

4) What changes in economic dispatch procedures would lead to more non-utility generator dispatch? If you think that changes are needed to current economic dispatch procedures in your area to better enable economic dispatch participation by nonutility generators, please explain the changes you recommend.

5) If economic dispatch causes greater dispatch and use of non-utility generation, what effects might this have – on the grid, on the mix of energy and capacity available to retail customers, to energy prices and costs, to environmental emissions, or other impacts? How would this affect retail customers in particular states or nationwide? If you have specific analyses to support your position, please provide them to us.

6) Could there be any implications for grid reliability – positive or negative – from greater use of economic dispatch? If so, how should economic dispatch be modified or enhanced to protect reliability?

U.S. Department of Energy
Washington DC 20585

Thursday, September 1, 2005

Mr. David Mohre
Executive Director
National Rural Electric Cooperative Association
4301 Wilson Boulevard
Arlington, VA 22203

Dear Mr. Mohre:

Section 1234 of the Energy Policy Act of 2005 requires the Department of Energy to conduct a study on the benefits of economic dispatch in the electricity industry. In particular, the law directs the Department to study:

> (1) the procedures currently used by electric utilities to perform economic dispatch;
> (2) possible revisions to those procedures to improve the ability of nonutility generation resources to offer their output for sale for the purpose of inclusion in economic dispatch; and
> (3) the potential benefits to residential, commercial and industrial electricity consumers nationally and in each state if economic dispatch procedures were revised to improve the ability of nonutility generation resources to offer their output for inclusion in economic dispatch.

The Act provides a definition of economic dispatch, and directs the Department to offer recommendations to Congress and the States for legislative or regulatory changes. This study must be completed in time for the Department to submit its report, with appropriate recommendations, to Congress and the states by November 7, 2005. DOE's Office of Electricity Delivery and Energy Reliability has tasked Joe Eto (at the Lawrence Berkeley National Laboratory) and Alison Silverstein to perform this study.

Because the tight schedule will not permit us to conduct fresh analysis of the topic, I have directed them to collect existing information and analysis about economic dispatch, and to draft a report drawing on that material. To that end, I understand that Alison Silverstein has spoken with you and that you have agreed to support this research by sharing this request with the members of your stakeholder organization and inviting them to share their views and information directly with us. The Department appreciates your support of this effort very much.

Attached is a short list of questions on how economic dispatch is now practiced, and how it might be changed in the future. We invite interested parties to prepare answers to these questions and send them **no later than September 21 to** Economic.Dispatch@hq.doe.gov, including such studies, testimony from regulatory proceedings, or other materials that can help Joe and Alison understand the issues and the submitter's views and concerns.

We realize that this schedule allows little time for gathering and submitting this material, so we thank you and your members in advance for your understanding and timely assistance. The statute requires DOE to update this study every year, so it is likely that issues not fully addressed in this initial study will get more attention in the future.

If you have any questions about the study, please contact me at David.Meyer@hq.doe.gov or Alison Silverstein at alisonsilverstein@mac.com.

Sincerely,

David H. Meyer
Acting Deputy Director
Office of Electricity Delivery and
Energy Reliability
U.S. Department of Energy

This same letter was sent to:

Ms. Sue Kelly at American Public Power Association
Mr. David Owen at Edison Electric Institute
Ms. Nancy Bagot at Electric Power Supply Association
Mr. John Anderson at Electricity Consumers Resource Council
Mr. James Torgerson at Midwest ISO for the ISO-RTO Council
Commissioner Jimmy Ervin, North Carolina Utilities Commission, for the National Association of Regulatory Utility Commissioners, Electricity Committee
Commissioner Phyllis Reha, Minnesota Public Utilities Commission, for the NARUC Energy Resources and the Environment Committee
Mr. David Cook at North American Electric Reliability Council

APPENDIX B

LIST OF SURVEY RESPONDENTS

Alabama Public Service Commission
Alberta Electric System Operator
Allegheny Power and Allegheny Energy Supply
Alliant Energy
Ameren Corporation

American Electric Power
American Public Power Association
American Transmission Company
Arizona Public Service/ Pinnacle West Corp.
Arizona Electric Power Cooperative, Inc

Arkansas Public Service Commission
Avista Utilities
Bonneville Power Administration
California ISO
California Public Utilities Commission

Calpine Corporation
Casazza, Jack
CenterPoint Energy
Cogeneration Association of California
Con Edison Energy

Constellation Energy Commodities Group
Consumers Energy
Dayton Power and Light
Detroit Edison
District of Columbia Public Service Commission

Dominion Resources Services
Duke Power
ECAR
Edison Electric Institute
Electric Power Supply Association

Entergy Services, Inc.
ERCOT
Florida Public Service Commission
Florida Reliability Coordinating Council
Hawaiian Electric Company

Idaho Power Company
Idaho Public Utilities Commission
INGAA Foundation
International Transmission Company
Iowa Utilities Board

ISO New England
ISO/RTO Council
Kansas City Power & Light
Kansas Corporation Commission
Kentucky Public Service Commission

Large Public Power Council
LG & E Energy Services Corp.
Lively, Mark B.
Maryland Public Service Commission
MEAG Power

MidAmerican Energy Company
Midwest ISO
Missouri Public Service Commission
National Rural Electric Cooperatives Association
NC Municipal Power Agency #1

Nebraska Public Power District
New Jersey Board of Public Utilities
New York Department of Public Service
New York Independent System Operator
New York Transmission Owners

NiSource
North Carolina Electric Membership Corp.
North Carolina Municipal Power Agency 1
North Carolina Utilities Commission
North Dakota Public Service Commission

Ohio Public Utilities Commission
Oklahoma Corporation Commission
Oklahoma Gas and Electric Company
Omaha Public Power District
Otter Tail Power Company

PacifiCorp
PJM Interconnection
Portland General Electric
PPL Corporation
Progress Energy (Carolina Power & Light)

Public Utility District 1 of Cowlitz County; PUD 2 of Grant County; PUD 1 of Pend Oreille County (joint filing)
Santee Cooper
Sierra Pacific
South Carolina Electric and Gas
South Carolina Public Service Commission

Southern California Edison
Southern Companies
Southwest Power Pool, Inc.
SUEZ Energy North America
Tennessee Valley Authority

TXU Wholesale
Utah Public Service Commission
Virginia State Corporation Commission
Washington Utilities and Transportation Commission
Western Farmers Electric Cooperative

Wisconsin Public Service Corporation
Xcel Energy