Paper accepted for presentation at 2009 IEEE Bucharest Power Tech Conference, June 28th - July 2nd, Bucharest, Romania

Functional Requirements for Southwest Power Pool Energy Imbalance Market Dispatch

P. Shamsollahi, *Senior Member, IEEE*, and V. Van Acker, *Member, IEEE*

***Abstract*--This paper discusses high-level functional requirements of the Energy Imbalance Service (EIS) market for the Southwest Power Pool (SPP) Regional Transmission Organization (RTO), in the USA. SPP has taken a controlled and step-by-step approach towards a full market model. Therefore, SPP has tried to introduce the EIS market on top of the traditional Market Participant (MP) activities with minimal impact. Currently in SPP, the EIS market is providing a central pool dispatch of energy imbalance in the Real-Time (RT) operations without Day-Ahead (DA) energy or Ancillary Services (AS) markets. Offering resources into the market is voluntary. This model of the light-weight electricity market is quite different than other major markets in the US, especially those in the northeast. The focus of this paper is on the dispatch model in the EIS market with emphasis on different constraint types. The EIS market dispatch is based on the nodal pricing like other major US electricity markets.**

***Index Terms*—Electricity Markets, Security Constrained Economic Dispatch, Deregulation, Regional Transmission Organizations.**

I. Nomenclature

SPP:	Southwest Power Pool
EIS:	Energy Imbalance Service
SCED:	Security Constrained Economic Dispatch
RTO:	Regional Transmission Organization
FERC:	Federal Energy Regulatory Commission
NERC:	North American Electric Reliability Council
LMP:	Locational Marginal Price
LIP:	Locational Imbalance Price
DA:	Day-Ahead
RT:	Real-Time
AS:	Ancillary Services
URD:	Uninstructed Resource Deviation
MP:	Market Participant
ICCP:	Inter Control Center Protocol
LSE:	Load Serving Entity
GenCo:	Generation Company

II. Introduction

DERGULATION of the electricity industry has created a lot of interest and change around the world. The main driving force behind the deregulation is to create a competitive environment for the ultimate goal of reduction of cost to consumers. An independent study on the impact of SPP EIS market has estimated that the entire US eastern interconnection would realize $1.2 billion in production cost savings over ten years, over half of which would flow to SPP customers.

Generation companies may benefit from the market by reducing their generation and having the option to buy lower cost generation from the market to serve their load obligations. They can also benefit from offering their generation to a larger customer base. Load serving entities may benefit from more competition among suppliers which should lower the prices.

Over the last decade or so, many markets have been created in the world. More specifically, in the US, markets have been started in the New England (ISO-NE), east (PJM), Texas (ERCOT), New York (NYISO), California (CAISO) and the mid west (MISO) [1]. The last one to join the deregulation trend in the US is the SPP RTO which started its EIS market on February 1, 2007.

SPP was established in 1941 when 11 regional power companies joined to keep an Arkansas aluminum factory powered around the clock to meet critical defense needs during World War II. Subsequent to the war, the executive committee of SPP decided to maintain the relationships between the companies in order to continue to offer the benefits of coordinated operation of electric systems throughout the SPP region. In 1968, SPP became one of the ten original sub-councils of the NERC (Fig. 1). Later on in 1997, it became one of now 18 NERC Reliability Coordinators (RC) covering North America.

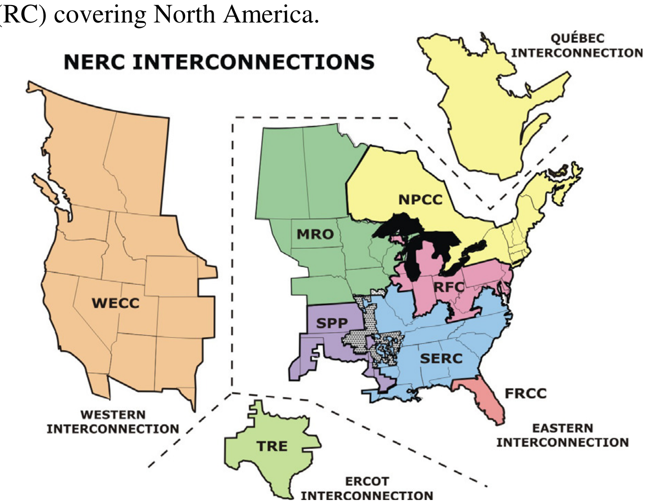

Fig. 1. NERC Interconnections (from NERC website)

Payman Shamsollahi is with AREVA T&D Inc., Redmond, WA 98052 USA (e-mail: payman.shamsollahi@areva-td.com).

Vincent Van Acker is with AREVA T&D Inc., Redmond, WA 98052 USA (e-mail: vincent.van.acker@areva-td.com).

SPP is mandated by both the FERC, as an RTO, and by NERC, as a member, to ensure reliable operation of the grid. SPP covers whole or parts of eight states: Arkansas, Kansas, Missouri, Mississippi, Louisiana, New Mexico, Oklahoma and Texas with a population of over 18 million people. It covers 255,000 square miles of service territory with 52,000 miles of transmission lines and more than 450 generating units representing an installed capacity of over 55 GW. SPP served a peak load of 44 GW in 2008. It is part of the eastern interconnection in the US and is connected to the western interconnection and ERCOT (Texas) interconnection via HVDC ties.

SPP provides many services to its members. The following lists the major services that SPP provides:

- Transmission Tariff Administration
- Reliability Coordination
- Regional Energy Scheduling
- Transmission Expansion Planning
- Market Operations

The focus of this paper is on the market operations and more specifically on the dispatch model in the SPP market.

III. EIS Market Overview

The energy imbalance market, in short, is the interaction between buyers and sellers of energy for the balance of the real-time metered load (or generation) and its scheduled value by the MPs. SPP provides the infrastructure needed to offer, clear and dispatch the resources for the Energy Imbalance Service while honoring reliability and system limitations. Energy schedule contracts are bilateral contracts that MPs enter in to buy/sell energy. MPs may also schedule energy to serve their own load (i.e. Native Load Scheduling or NLS). The balance of these schedules and the real-time load is provided as a service by the RTO in a centrally dispatched pool. The financial impact of the EIS market on both generation and loads is within the control of MPs by the use of energy schedules.

Currently, there is no central commitment of resources in SPP. Commitment of resources is performed by the MPs and submitted to SPP via resource plans. MPs submit their energy offers to the RTO where an SCED function clears the offers to achieve lowest cost of operation. Currently, there is no mechanism to submit a demand bid into the market. Generation dispatch signals will be sent to MPs via XML over the internet and also by the ICCP. The EIS market ensures that real-time load is served using least cost generation offers while maintaining system security and respecting its limitations.

The SPP world was quite different before the start of the market. Prior to the EIS market, the imbalance was offset by the regulation in real-time and regulating units were paid through bilateral or financial agreements. An expected outcome of the market is to reduce the required regulation and reserves carried by the MPs. In the new deregulated framework, SPP will assign a LIP to each node in the system. The LIP is the marginal price of providing next incremental amount of energy which includes production and congestion components. Although mathematically equivalent to LMP, LIP is the preferred nomenclature for SPP in order to emphasize that the nature of the market settlements is on imbalance. SPP will settle each node financially, based on the location, on an hourly basis. LIPs are posted on the SPP website right after they are calculated for the hour. They are subject to revision before being finalized.

Transmission rights in the SPP market is physical, as opposed to financial like many other US markets. Physical rights have the use-it-or-lose-it characteristics, whereas financial rights can bring in revenue for the owner even if they are not used.

SPP market is a single settlement market (no financial DA market). This may seem to increase risks for participants. However, bilateral transactions can create some form of risk management, especially in a market that, on average, less than 10% of the load is subject to RT prices.

IV. Market Participant Data

SPP market participants submit a variety of information to the market. The following categories of data are submitted by the MPs for market operation.

A. *Resource Plan*

Resource plan contains information about resource operational data (like Min/Max and ramp rate) and commitment status. Possible commitment (or resource) statuses along with their usages are summarized in Table I.

TABLE I
Commitment Statuses in the Resource Plan

Commitment Status	Usage
Available	On-line & controllable resource under market command.
Unavailable	Off-line resource.
Self-dispatch	On-line & controllable resource under MP's command.
Supplemental	Off-line resource that can provide supplemental reserve.
Manual	On-line & uncontrollable resource (e.g. in testing, startup or shut down mode).

Resource plan information is used to clear the market in its most critical function, SCED, which happens every 5 minutes targeting 15 minutes ahead. Resources will get a dispatch signal every time the SCED function is executed. The function will also create a nodal price (LIP) for each location in the system that needs to be settled. MPs may offer their resources into the energy imbalance market or self-schedule them to serve their native load or energy obligations to other MPs.

B. Capacity Plan

Capacity plan contains information about how the MP is intending to fulfill its AS obligations. This could be either through self-supply or bilateral agreements with other MPs. These are used to inform the RTO about the scheduled values of different types of ancillary services. Table II shows different types of AS in the SPP market.

TABLE II
ANCILLARY SERVICES IN THE SPP MARKET

Ancillary Service	Purpose
URS	Regulation service in the upward direction.
DRS	Regulation service in the downward direction.
SPIN	Spinning reserve.
SUPP	Supplemental reserve.

RTO will run separate functions in the DA and HA time frames to ensure consistency of the capacity plans and resource plans as well as sufficiency of the scheduled AS against obligations to the RTO.

C. Energy Schedules

This contains information about any energy scheduled to flow to either serve MP's own load, or sell to (or buy from) another MP. Energy schedules are submitted to inform RTO of the intent of the MP to self-supply its load or to sell/buy energy to/from other MPs. The energy schedules are used in the settlement system in conjunction with metered load and generation to find the differences between scheduled amounts and actual amounts, which is the EIS.

D. Load Forecast

This is the forecasted load of the MP. Load forecasts are submitted by LSEs so that the RTO can perform its supply sufficiency functions as required by the market rules. The function is performed on several levels including, MP, Balancing Authority (BA) (or control area) and SPP system. In general, an MP is expected to have enough capacity planned to cover its load and AS obligations.

E. EIS Offers

This is the energy price offer to produce energy in $/MWh. EIS offers are also submitted by GenCos to let SPP know of the offer price of different MW bands in form of a piece-wise linear function. The offers are used by the SCED function to clear the EIS market in real-time.

F. Metering Data

These are the after-the-fact measurements sent to the market system for settlement of the charges and credits, by location and on an hourly basis.

V. MP & Market Activities

This section provides a high-level timeline for MP and market activities.

A. MP Activities

As discussed before, MPs submit a variety of information to the market system at different times. The following lists major MP activities:

- **Resource Plans, EIS Offers and Load Forecasts**: These are submitted several days ahead of the Operating Day (OD). These can be updated up to a certain time before the start of the operating hour.
- **Capacity Plans**: These are submitted DA. They can be updated up to a 45 minutes before the start of the operating hour.
- **Energy Schedules**: These are submitted and updated at any time up to 20 minutes before real-time.
- **Meter Data**: Load, generation and interconnection meter data are submitted up to four days after RT.

B. Market Activities

SPP market core activities can be divided into the following categories:

1) Day-Ahead

Market activities start on the day before the OD (i.e. DA). SPP first publishes the RTO load forecast and AS obligations early in the morning. MPs have time to adjust their submitted data based on that information. Throughout the day at different time points, SPP executes the following functions:

a) Posting of Load Forecast & AS Requirements

The posting of the RTO load forecast (estimated by SPP) may be done several days ahead.

b) Capacity Plan Matching

This is to ensure bilateral AS agreements are matching between counterparties.

c) Resource Plan Validation (RPV)

This function checks the consistency of resource plans and capacity plans for feasibility of the energy and AS schedules.

d) DA Congestion Management Study

This is the first evaluation of the transmission security for the next day.

e) System/BA/MP Capacity Sufficiency Checks

This is to check load forecast vs. committed resources capacity, taking into account AS schedules.

f) MP Notification

Market participants receive notifications via internet (in XML) about the results of the above activities and will take necessary action to address them.

2) Hour-Ahead

DA activities continue into the operating day making a transition into the Hour-Ahead (HA) activities which include:

a) HA Congestion Management Study

This is to identify potential transmission constraints or other operating violations for the upcoming hour.

b) HA Flow Gate Calculations

This is to calculate projected flow gate flow (and its components). The data needs to be reported to NERC for possible TLR actions.

3) Real-Time

The most critical market activities are happening close to real-time. These activities include:

a) State Estimator

It runs every 2 minutes to provide state of the power system (e.g. generation, load, connectivity) to other applications.

b) Contingency Analysis

It runs every 4 minutes to provide power grid security information to the market.

c) SCED Function

It is executed every 5 minutes and 15 minutes ahead of the target dispatch time point. As part of its solution, this function calculates dispatch instructions and LIPs used for the settlements.

d) Communication of the Dispatch Instructions

This is sent to resources via XML (internet) and ICCP (EMS).

e) Communication of NSI

Net scheduled interchange is sent to BAs via ICCP link.

f) RT Flow Gate Calculations

Flow gate flows and components are reported to the NERC.

4) Post Real-Time

The ex-ante prices calculated by SCED function, along with metered energy, are used in the settlements system along with energy schedules to calculate EIS charges after the fact. Resource MW deviation from dispatch instructions, called URD (Uninstructed Resource Deviation), is also calculated after the fact and reported to the settlements. MPs might be subject to charges if they did not follow the instructions. Initial and final settlement statements are sent to MPs in 5 and 45 days after OD, respectively.

VI. Market Subsystems

SPP EIS market consists of several subsystems running on a variety of platforms. Fig. 2 below shows a high-level diagram of the system.

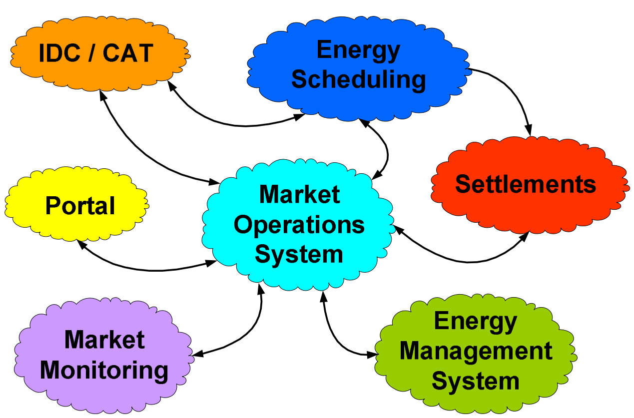

Fig. 2. SPP Market Subsystems

MPs enter market data into the system via SPP Portal. The portal provides a web-based UI for the MPs to:

- Enter resource plans, capacity plans and EIS offers
- View market solution results
- Submit metering data
- View settlement statements
- View market notifications

The heart of the system is the Market Operations System (MOS). The MOS is responsible for calculating dispatch instructions and LIPs. This information is sent to the settlements system for billing. Energy schedules are entered into the system via the Energy Scheduling System. These schedules are sent to MOS for operating the system as well as to the settlements for calculation of EIS charges.

The market system obtains real-time and other operational data from the Energy Management System (EMS) and sends dispatch signals back to resources via XML and ICCP. A Market Monitoring system gathers market data (including MP data) and analyzes them to ensure compliance to the market protocols by the MPs and also to ensure no MP is participating in uncompetitive practices or market gaming. The Market Monitoring System also calculates offer caps and may enforce them on a selected set of pivotal resources whenever a transmission constraint is active. Offer caps were instituted per requirements on the market by the FERC.

The SPP market has an interface to the NERC Interchange Distribution Calculator (IDC) system to provide flow gate constraint flow data and get schedule curtailment and market flow relief instructions during Transmission Loading Relief (TLR), as described in the NERC Standard IRO-006-3. Another subsystem of the SPP market related to congestion management is the Curtailment and Adjustment Tool (CAT) which is responsible to curtail a category of energy schedules that are not visible to NERC IDC tool.

VII. Dispatch & Pricing

SPP employs a Security Constrained Economic Dispatch (SCED) algorithm based on the submitted offer prices. The security limitations are identified by running an N-1 contingency analysis. If, as a result of the contingency analysis, an equipment overload is anticipated, additional transmission constraints are created and added to the original ED problem, which is then re-solved.

The pricing signals (impacted by the congestion) are fundamental to the economic operation of the SPP market and are derived from the state of the congestion of transmission lines and transformers throughout the system. In this section, a closer look is offered to the economic dispatch model used at SPP, along with the constraints involved. At the end of this section, more details are provided about the calculation of the LIPs.

A. SCED Model

The economic dispatch is a minimum cost problem where the objective function, shown in (1), can be formulated as follows:

$$Min \sum_{i=1}^{N_G} \left[\int_0^{P_i} C_i(P_i).dP + \sum_{j=1}^{N_C} K_j V_j(P_i) \right] \quad (1)$$

where,

P_i is the decision variable representing output of generator i

N_G is the number of committed generators

$C_i(P_i)$ is the cost function of generator i

N_C is the number of different types of constraints affecting each resource

K_j is the violation penalty factor of constraint j

V_j is the amount of violation of constraint j as a linear function of P_i

The main components of the (1) are:

1) Deployment Cost Component:

This is the sum of the cost of each unit which is calculated as the product of the unit dispatch MW level P_i and the corresponding production cost $C_i(P_i)$ of the unit (at MW level P_i). These costs are represented by the integral in the first term in (1).

Since the SPP market does not allow load entities to enter load bids, the market clearing is in fact a one-sided auction. Loads at SPP are price takers.

2) Violation Cost Component:

To limit the economic dispatch problem to solutions that are physically and technically feasible, several constraints are imposed. For robustness of the solution under conditions where infeasibilities exist, violations of the constraints are penalized and added as a cost to the objective function. The types of constraints considered here are:

- Power balance constraint,
- Unit capacity constraints,
- Unit ramp-rate constraints, and
- Transmission constraints

Only power balance and transmission constraints have a direct impact on the LIPs. The violation costs are represented by the second term in (1).

B. Constraints

In order to comply with the laws of physics and the market rules, as well as with the technical limitations of the equipments, the following constraints are included in the SCED model.

1) Power Balance Constraint

The total sum of the generator outputs should match the system wide load forecast plus exports out of the market footprint. This constraint is captured in (2):

$$\sum_{i=1}^{N_G} P_i = LF + NetExport \quad (2)$$

where,

LF is the system wide load forecast

$NetExport$ is defined as the sum of the exports out of the market footprint minus the imports into the market footprint.

2) Unit Capacity and Reserves Constraints

The output of a generating unit should be within its capacity limits, taking into account ancillary services reserved. The following models unit capacity constraints:

$$P_i^{\min} + DR_i \le P_i \quad (3)$$

$$P_i + UR_i + SPIN_i + SUPP_i \le P_i^{\max} \quad (4)$$

where,

$P_i^{\min}$ is the minimum capacity of generator i

$P_i^{\max}$ is the maximum capacity of generator i

DR_i is the down regulation capacity of generator i

UR_i is the up regulation capacity of generator i

$SPIN_i$ is the spinning reserve capacity of generator i

$SUPP_i$ is the supplemental reserve capacity of generator i

3) Unit Ramp Rate Constraints

Due to technical limitations, the MW level of the unit can only decrease or increase so much over the course of a time period. This is specified by the ramp rate of the unit, and may be dependent on the output level of the unit.

$$RR_i^{down} \le \left(P_i - P_i^{prev}\right) / \Delta t \le RR_i^{up} \quad (5)$$

where,

RR_i^{down} is the generator down-ramp rate limit (MW/min).

RR_i^{up} is the generator up-ramp rate limit (MW/min).

P_i^{prev} is the output of generator Δt minutes earlier.

4) Transmission Constraints

Congestion management is achieved by including transmission constraints in the model. In the case of SPP, sensitivity factors are used to model linearized form of these constraints. They are recalculated for each economic dispatch solve. The general form of a transmission constraint is shown in (6).

$$\sum_{i=1}^{N_G} SF_i^k \; P_i \le L^k \quad (6)$$

where,

SF_i^k is the shift factor of generator i with respect to element k

L^k is the loading limit of element k

From a constraint management perspective, the transmission constraints have been subdivided into the following two main classes.

a) Contingency Analysis Constraints

These are constraints that have been created automatically by the contingency analysis process. These reflect power grid transmission limitations with regards to the specific solution point.

b) Manual Constraints

These are constraints that are manually activated by the market operator. Among those are flowgate constraints and constraints from earlier studies, such as hour ahead or congestion management studies.

C. Locational Imbalance Pricing

The key aspect of congestion management is the locational marginal pricing, or in the context of SPP, Location Imbalance Pricing (LIP). In general, the LIP at a location k consists of three components as shown in (7).

$$LIP_k = LIP_{sys,k} + LIP_{cong,k} + LIP_{loss,k} \quad (7)$$

where,

$LIP_{sys,k}$ is the system marginal price component of location k

$LIP_{cong,k}$ is the congestion component of location k

$LIP_{loss,k}$ is the loss component of location k

The component $LIP_{sys,k}$ corresponds to the system marginal price and is the same at every location. It represents the dollar amount it would cost to dispatch an additional system load MW spread proportionally over the existing loads, and in the absence of congestion.

The congestion component $LIP_{cong,k}$ is location dependent, and is derived from the shadow prices of the transmission constraints as expressed in (8).

$$LIP_{cong,k} = \sum_{c=1}^{Nc} SF_k^c \ \rho^c \quad (8)$$

where,

SF_k^c is the linear sensitivity factor of the injection at location k, with respect to transmission constraint c. The sensitivity factors are recalculated for each SCED run.

ρ^c is the shadow price of the transmission constraint c.

As a result, areas that are located at the receiving end of transmission branches that tend to be congested will experience higher LIP values in average.

As far as the SPP market is concerned, the loss component $LIP_{loss,k}$ in (7) is not considered.

VIII. Market Results

SPP started its EIS market on Feb 1st, 2007. It has 16 separate balancing authorities that, individually, are responsible for balancing supply and demand within their territories. Since the market went live, an increase has occurred in the amount of new generation interconnection requests as well as transmission expansion. Outages as a percentage of peak load also went down after the start of the market. The volume of energy resulted from the EIS market was roughly 8% of total load in the first year of the market [2]. This represented a net trade benefit of roughly $103 million for the first 12 months of the market operation [3].

The average electricity price in 2007 was about $49 which is in-line with two neighboring RTOs (ERCOT and MISO). This shows that, SPP prices are competitive with neighboring areas. The average price variation among different locations within SPP is less than roughly 15%. This price variation is due to congestion patterns in SPP and shows that transmission bottlenecks (and control thereof via market mechanisms) are not creating a big price spread. Table III shows some price indices for SPP, MISO and ERCOT.

TABLE III
MARKET PRICE INDICES FOR SPP AND NEIGHBORING MARKETS

Region	Average Price	Max. Price	Min. Price	Median Price
SPP	$49.18	$386.16	($105.82)	$50.28
MISO	$47.37	$622.63	($35.75)	$36.84
ERCOT	$53.00	$1,500.00	($246.05)	$48.77

Market participation in the EIS market is voluntary. In the first year of the market, on average, roughly 81% of the capacity was made available for dispatch. This shows a big participation from market players. However, there were some concerns about the dispatchable range and ramp rates provided to the market. In 2008, SPP got approval from FERC to allow external generators to participate in the EIS market. This step creates more competition and may drive prices even lower.

One of the benefits that a market is supposed to provide is to create less congestion through market tools. In the SPP, prior to the market, the only tool available was curtailment of schedules monitored by NERC. After the market, re-dispatch and other tools relieved 85% of congestion which shows a clear benefit in the area.

SPP is now exploring the possibility of day-ahead, ancillary services and financial transmission rights markets.

IX. Acknowledgment

The authors gratefully acknowledge valuable comments of R. Dillon, SPP Director of Market Development & Analysis.

X. References

[1] X. Ma, D. I. Sun, and K.W. Cheung, "Evolution Toward Standardized Market Design," *IEEE Trans. on Power Systems*, May 2003.

[2] *2007 State of the Market Report*, Available: http://www.spp.org/

[3] *SPP Press Release, Apr. 28 2008,* Available: http://www.spp.org/

XI. Biographies

Payman Shamsollahi (S'1993, M'1997, SM'2001) received his BSEE and MSEE from Tehran University, Iran, in 1989 and 1990, respectively, and his Ph.D. degree from University of Calgary, Canada in 1997. He is currently a project engineer with AREVA T&D Inc. He served as the lead project engineer for the SPP market project from 2004 to 2007. His main interests are deregulation applications, artificial intelligence and power systems control.

Vincent Van Acker (S'1994, M'2001) graduated with a degree in Electrotechnical-Mechanical Engineering from the University of Ghent, Belgium in 1992. He received his M.Sc. degree in Electrotechnical Engineering and Computer Science from the University of Porto, Portugal in 1995, and his Ph.D. degree in Electrical Engineering from Iowa State University in 2000. He is currently employed by AREVA T&D Inc. as a principal power system engineer with the Market Applications group.