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Methodology for Automatic Zone Creation/Merging/Partitioning

CALIFORNIA ENERGY COMMISSION

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Abstract

The objective of this report is to investigate methodologies for zone creation suitable for zonal pricing by the California ISO. It is recognized that in meshed networks, zones are only approximations to individual node pricing. The objective, however, is to create zones that closely approximate the "correct" nodal prices under most conditions and where the majority of the "commercially significant" value of the locational pricing is captured. The report starts with a review of congestion concepts, then proceeds with a review of nodal and zonal pricing, it then reviews the CAISO's own criteria for zone partitioning, it then evaluates the notion of "nodal price patterns," and finally, using the notion of nodal price pattern it defines a methodology for zone creation and partitioning and finally demonstrates its used by means of an example. It concludes with some suggestions and recommendations.

Methodology for Automatic Zone Creation/Merging/Partitioning

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Methodology for Automatic Zone Creation/Merging/Partitioning

I Introduction

The objective of this report is to investigate methodologies for zone creation suitable for zonal pricing by the California ISO. It is recognized that in meshed networks, zones are only approximations to individual node pricing. The objective, however, is to create zones that closely approximate the "correct" nodal prices under most conditions and where the majority of the "commercially significant" value of the locational pricing is captured. The report starts with a review of congestion concepts, then proceeds with a review of nodal and zonal pricing, it then reviews the CAISO's own criteria for zone partitioning, it then evaluates the notion of "nodal price patterns," and finally, using the notion of nodal price pattern it defines a methodology for zone creation and partitioning and finally demonstrates its used by means of an example. It concludes with some suggestions and recommendations.

The report is based almost entirely on properties of the transmission network itself. It is shown that, although nodal prices and zonal prices depend on the cost of generation, the price *patterns* associated with zonal and nodal prices are largely a function of the network and do not depend on the prices at the various generators. Thus, it is possible for the most part to separate the concept of zone partitioning from the cost and location of individual generators. The exception to this rule is the general desire to ensure that there are a sufficient number of generating units within any one "zone" and the further desire that zones need not be created unnecessarily unless there are sufficient price differences. To this end, the report reviews the "5% rule" used by the CAISO to trigger zone partitioning or creation.

This report studies mainly congestion management by locational pricing methods. There are four main sections to this report.

Section II describes the nature of transmission congestion.

Section III introduces nodal pricing and zonal pricing systems. Similarities and difference of these two pricing systems are studied. It also includes some concept examples showing the different situations that arise for radial and networked systems.

Section IV reviews the congestion management method used by CAISO as well as the Market Power Mitigation method. The CAISO uses a 5% rule to create congestion zones. This section also discusses the details and the rationale for this method. It uses a real "case study" to illustrate the method. All the data used in this section comes from the CAISO itself.

Section V describes the Methodology for Automatic Zone Creation/Merging/Partition developed at University of Wisconsin – Madison. It also illustrates some case studies of

intra-zonal congestion and inter-zonal congestion management and zone creation results by means of examples.

An appendix illustrates several of the price patterns that are apparent within the California system as a result of observed congestion conditions. These price patterns are suggestive of possible zonal organization of the system. In particular, they illustrate the observation that a pure zonal structure is imperfect and that in a many cases a few locations are far more influential on congestion conditions than others. We have elected to call these locations "hot spots." In the end, if the CAISO would like to retain its zonal market structure organization, it would do well to isolate those locations that depart considerably from the zonal price and resort to nodal pricing for these specific locations, in addition to the zonal price used for most trades. The system would then resemble the New York ISO system, which is mostly zonal but it is supplemented by the inclusion of some locations (many of the generators) as separate tradable points.

II. Transmission Congestion

The presumption here is that the system is operated by the CAISO based on the submission of number of "schedules" by individuals or individual "Security Coordinators." These schedules are supposed to represent a balance between scheduled supply and scheduled generation. The individual schedules, however, may lead to impossible transmission congestion conditions. Transmission Congestion is the condition where there is insufficient transmission capability to simultaneously implement all Preferred or Revised Schedules that Scheduling Coordinators (SCs) submit to the ISO in the forward markets. The most economically efficient way to handle congestion is by means of locational pricing: charging for the congestion to users of the grid based on the value of the transmission congested facility. The principles for Congestion Management developed by the CAISO were presented by the "Zonal Forward" group. The main policy objectives of the Congestion Management methodology proposed by the zonal Forward group are:

a) Maximize the efficient use of the transmission grid;

b) Create appropriate long-term locational price signals;

c) Provide stable, comparable and predictable prices for Congestion Management;

d) Prevent discrimination;

e) Minimize ISO involvement in the forward Energy markets;

f) Maintain comparability and separation of the Energy markets conducted by various SCs;

g) Develop a Congestion Management model that does not provide incentives for destructive gaming

Transmission grid capability is limited by transmission interface loading limits established by the ISO for the transmission system under the ISO's operational control. The transmission transfer capability and loading limits are determined based on the steady state limits of transmission facilities required to meet North American Electric Reliability Council (NERC) and Western Systems Coordinating Council (WSCC) operational standards, as well as security standards (thermal ratings, stability, voltage and contingency limits, etc.).

Transmission management through proper pricing system is widely used in the North America. Zonal pricing system is used by CAISO, nodal pricing system is used by PJM, and a hybrid approach (mostly nodal, but with a limited number of nodal locations) is used by the NYISO. Most recently, NEPOOL has adopted, in effect, a nodal pricing methodology similar to that of PJM for future implementation. Also quite recently, Texas (ERCOT) has elected to implement a zonal approach, but with a provision to revisit the issue at a future date based on performance.

III Zonal Pricing and Nodal Pricing

2.1 Introduction to Zonal Pricing and Nodal Pricing

"Zones are defined as areas where congestion is infrequent and can be easily priced on an average cost basis. By definition, congestion within zones is infrequent and possibly difficult to predict. Therefore, financial rights will be difficult to auction and to resell in a secondary market. Congestion between zones is defined to be frequent with large impacts. Therefore, marginal cost pricing promotes its efficient use. Marginal Cost of transmission is the value that market participants place on congested transmission. Marginal Cost is based on scheduling and bidding information for hourly consumption in the relevant forward or spot market. Marginal cost pricing provides the economic incentives that promote the allocation of the limited transmission capacity to the most cost-effective users." [1]

Zonal pricing begins with a definition of zones. Zone definition is more an art than a precise science, and it is subject to a great deal of judgment. At a minimum, zonal pricing is not unique. It is also subject to assumptions that go beyond the assumptions necessary to create the nodal prices themselves. Zonal pricing requires consideration of both inter-zonal and intra-zonal congestion.

The basic concept of nodal pricing is simple: the price at a node is the cheapest way in which power can be delivered to the node from the present set of marginal units in the system *without violating any of the system constraints in effect.* The key reason as to why nodal pricing works well in electricity markets is the fungibility of electricity as a commodity: there is no need to physically send "electrons." Nodal pricing works because the transportation of electricity can be replaced with a corresponding amount of electricity at the receiving end. (The same principle would not work without modification in networks such as the Internet or for telephone networks. The objective in

these systems is not to deliver a message with certain characteristics, but to deliver a *specific* message. Substitution at the receiving end is not possible).

2.2 Nodal and Zonal Price Calculation and Case Study

2.2.1 Method for the Calculation of Nodal and Zonal Prices

A nodal price is the market-clearing price at a particular node. It represents the cheapest way to deliver power to a node in question under the specific conditions at the time while respecting all limits in effect. A zonal price, however, can be defined according to several different approaches:

a. Determining the non-constrained price, followed by an uplift calculation. This is the method adopted in [3, 5]. Calculating the uplift is a function of the generators assigned to increase and reduce their generation, as a consequence of the network constraint.

b. Maximum nodal price. Under this approach, the highest nodal price in the zone becomes the zonal price.

c. Average price. An average of all nodal prices leads to the zonal price. It is important to mention that all the prices are taken into consideration, regardless the capacity of each generating unit.

d. Weighted approaches. Two methods may be used.

d1. The zonal price is given by:

$$\frac{\sum_{1}^{n}(MaxPower * Price)}{\sum_{1}^{n} MaxPower} \qquad (1)$$

where *MaxPower* stands for the total capacity generation of each unit and *Price* is the price per MWh charged by the same unit. Finally, *n* is the number of units in the zone.

d2. In this case, the total capacity of each unit is replaced by the actual power generated at each unit (*Gen*), yielding:

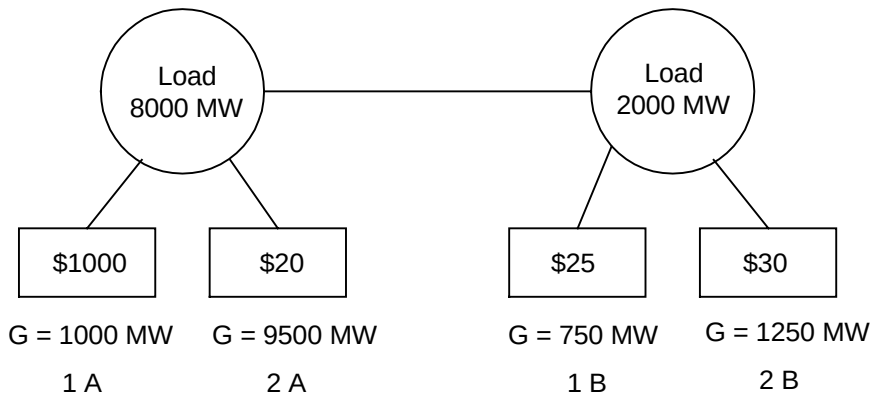
$$\frac{\sum_{1}^{n}(Gen * \mathrm{Pr}ice)}{\sum_{1}^{n} Gen} \qquad (2)$$

The methodologies described above will be discussed in greater detail in the next section, where the impact of different operating conditions is considered.

2.2.2 Case Study for a Radial System

In this case study, the simple two node system in [3] is used. The test system used here is a lossless two-bus system shown below. Load at bus A is 8,000 MW, load at bus B is 2,000 MW. The transmission line connecting both nodes has a thermal limit of 1,000 MW. The line is congested in all the cases considered here.

Case I



- Nodal price

Node A= $1,000.00 and Node B = $30.

Total cost to customers is 1000*8,000 + 30*2,000 = $8,060,000.

- Zonal Price

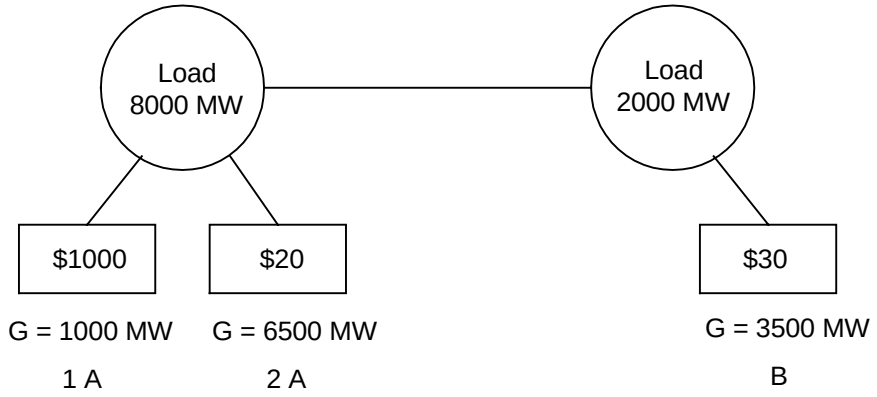
- unconstrained and uplift

The unconstrained price is $25. Because of the constraint in the transmission line, Generator 2A has to reduce its generation by 500 MW that must be generated by Generators 1B and 2B. The uplift is then given by:

uplift = (250*5 + 250*10 + 500*5)/10000 = 0.625

The total cost goes to $25.625. So, the total cost would be $256,250, which is cheaper than the nodal pricing. The other possibilities of zonal pricing, however, will not be considered, since in a practical situation, Generator 1A would have no reason to bid at $1,000.

Case II



- Nodal Price

The nodal prices are given by Node A = 1000 and Node B = 30.

The total cost is

Cost = 2000*30 + 8000*1000 – 1000*970 = 7,090,000.00

The term (1000*970) is the congestion rent.

- Zonal price

- unconstrained and uplift

The unconstrained price, in this case, is about to $30.00, since generators 2A and B tend to supply the load. Because of the transmission line limit, however, Generator B has to reduce its generation by 500 MW, whereas generator 1A has to increase its generation by the same 500 MW. It yields the uplift:

uplift = (500*0 + 500*970)/10000 = 48.50

The zonal price goes to $78.50, implying in the total cost to load of 785,000.00. This is much cheaper than the nodal cost.

- maximum price

This is certainly the worst case, since the zonal price goes to $1,000.00, escalating the total cost to $10,000,000.

- average

The average price is given by $350.00. The total cost goes to 3,500,000.00. This is cheaper than the nodal cost.

- weight method d1

The zonal price is given by

zonal price = (1000*1000 + 6500*20 + 3500*30)/11000 = 112.27

The value above leads the total cost to $1,122,700

- weight method d2

If the actual value generated is considered, the zonal cost is given by

zonal price = (500*1000 + 6500*20 + 3000*30)/10000 = 72.00

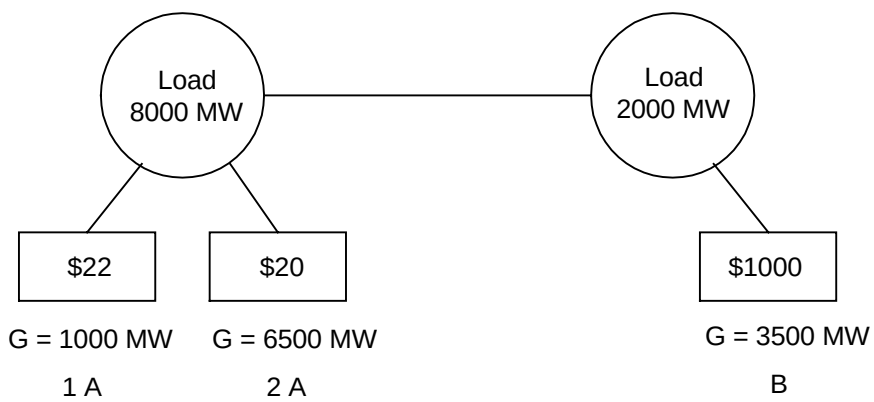
Under this condition, the total cost is $720,000.

Notice that, both approaches provide a cheaper price than the nodal approach. Actually, method d2 provides the cheapest cost among all the methodologies proposed.

- Comments

The results shown above lead one to conclude that zonal price may provide better prices to customers, even when a marginal generator is allowed to bid a higher price.

Case III



- Nodal price

Node A= 22 and Node B = 1000, which takes the total price to

Total cost = 8000*22 + 1000*2000 + rent congestion = 2,176,000.00 + rent congestion

Rent congestion = 500 * (1000 – 22) = 500*978 = 489,000

Interestingly, in this case the rent congestion tends to increase the total cost. Hence, the total cost is given by

Total cost = 2,176,000 + 500*978 = $2,665,000

- Zonal Pricing

- unconstrained and uplift

In this case, no uplift is needed, and the zonal price is given by the same value is obtained by method b (maximum value), which is equal to $1,000.00. The total cost is then

Total cost = $10,000,000, which is a lot higher than nodal price.

- maximum price

The maximum nodal price is given by $1,000.00. If this is taken as the zonal price, the total cost goes to $10,000,000.00, which is, certainly, the most expensive price.

- average

The average is given by (22 + 20 + 1000)/3 = $347.33. This price takes the total cost to $3,473,300, which is still bigger than the nodal price.

- weight method d1

At first, the total capacity is considered, yielding the zonal price:

zonal price = (22*1000 + 20*6500 + 1000*3500)/11000 = $332.00,

and the total cost is $3,320,000, and once again, the nodal price is better.

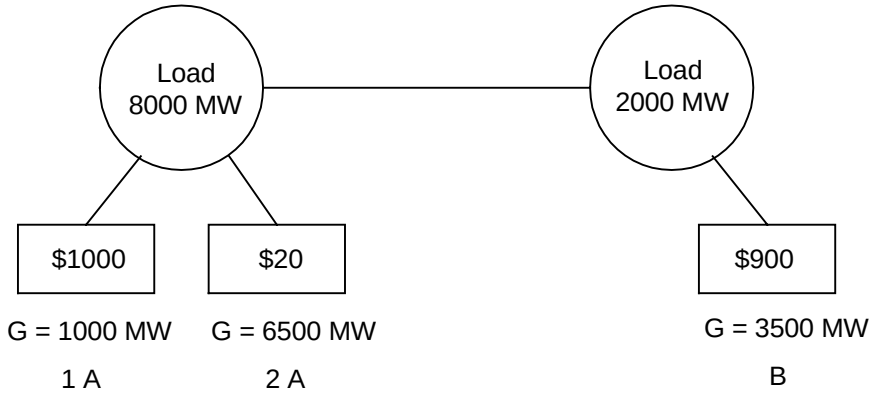
- weight method d2

When the actual generating value is considered, the following value is obtained:

zonal price = (22*1000 + 20*6500 + 1000*2500)/10000 = $265.20,

and the total cost goes to $2,652,000. This result is slightly better than that one provided by the nodal price.

Case IV



- **Nodal price**

Node A= $1000 and Node B = $900, yielding the total cost:

Cost = 8000*1000 + 2000*900 –1000*100 = 9,700,000

- **Zonal price**

- unconstrained and uplift

In this case, the price is given by $900. However, because of the transmission line constraint, Generator B has to reduce its generation by 500 MW, whereas Generator 1A has to increase its generation by the same 500 MW, providing the uplift:
uplift = 500*100/10000 = 5, and the total cost is given by $905.00. It takes the total cost to 9,050,000, which is less expensive than the nodal price.

- maximum price

If the maximum price is considered as the zonal price $1,000.00, the total cost will be even more expensive, rendering the nodal price as a better choice.

- average

The average price in this case is given by (1000 + 900 + 20)/3 =$640.00. The total cost goes to $6,400,000.00. This is cheaper than the nodal price, in contrast to the previous zonal price definitions.

- weight method d1

The first approach considers the total capacity of each generator:

zonal 1 = (1000*1000 + 6500*20 + 3500*900)/11000 = $389.00,

which is associated with a total cost of $3,890,000, that is, once more, cheaper than the nodal price.

- weight method d2

The second approach considers only the effective generation at each bus:

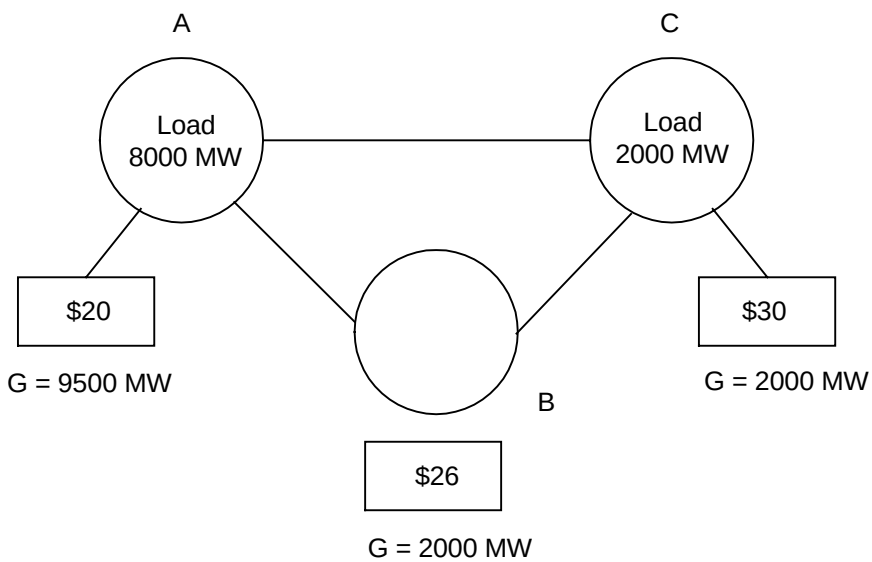
zonal 2 = (500*1000 + 6500*20 + 3000*900)/10000 = $333.00,

and a total cost of $3,333,000.00 is obtained. This value is even cheaper than the previous zonal prices obtained.

2.2.3 Case Study of a Network System

In this case study, the simple network system in [3] is used. There are three nodes in this system. The thermal limit on the transmission line between Node A and Node C is 1000 MW.

Case I



- **Nodal price**

Node A= $20 and Node C = $30, yielding the total cost:

Cost = 8000*20 + 2000*30 –1000*10 = $210,000,

Nodal price at Node B is $25.

- **Zonal price**

- unconstrained and uplift

In this case, the unconstrained zonal price is given by $26. However, because of the transmission line constraint, Generator A has to reduce its generation by 500 MW, Generator B back down 500 MW, Generator C increase 1000 MW.

uplift = [(500+500)*6 + (30-26)*1000]/10000 = 1,

zonal price is $27, total cost is $270,000.

- maximum price

The maximum price is $30, total cost = $30*10000 = $300,000.

- average

The average price in this case is given by (20 + 26 + 30)/3 =$25.33. The total cost goes to $25.33 * 10000 = $253,300.

- weight method d1

The first approach considers the total capacity of each generator:

zonal 1 = (20*9500 + 26*2000 + 30*2000)/(9500 + 2000 + 2000) = $22.37,

which is associated with a total cost of $223,700.

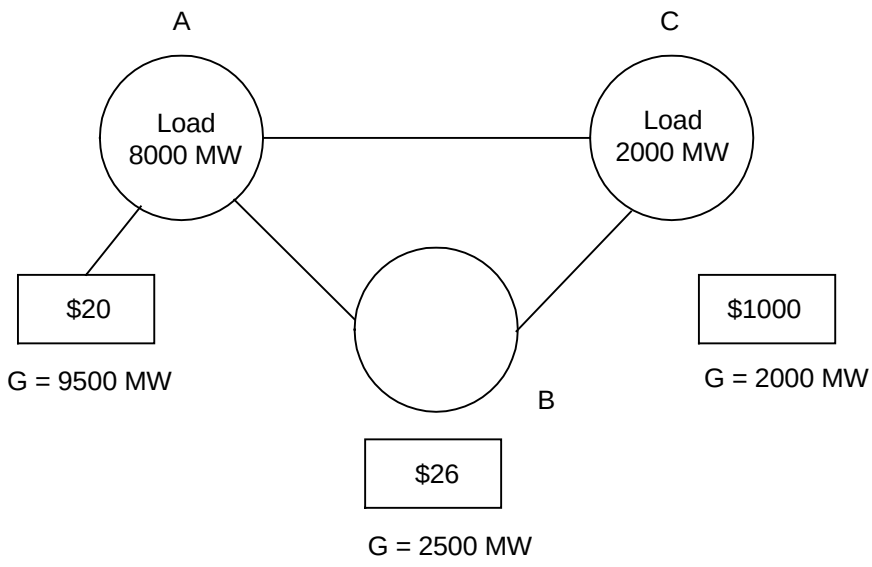
- weight method d2

The second approach considers only the effective generation at each bus:

zonal 2 = (20*9000 + 26*0 + 30*1000)/10000 = $21,

and a total cost of $210,000 is obtained.

Case II



- **Nodal price**

Node A= $20 and Node B = $26, yielding Node C = $32.

Cost = 8000*20 + 2000*32 = $ 224,000,

- **Zonal price**

- unconstrained and uplift

In this case, the unconstrained zonal price is given by $26. However, because of the transmission line constraint, Generator A has to reduce its generation by 500 MW, Generator B back down 500 MW, Generator C increase 1000 MW.

uplift = [(500+500)*6 + (1000-26)*1000]/10000 = 98,

total cost = (26+98) * 10000 = $1,240,000.

- maximum price

The maximum price is $1000, total cost = 1000*10000 = $10,000,000.

- average

The average price in this case is given by (20 + 26 + 1000)/3 =$348.67.
total cost = $348.67 * 10000 = $3,486,700.

- weight method d1

The first approach considers the total capacity of each generator:

zonal 1 = (20*9500 + 26*2000 + 1000*2000)/(9500 + 2500 + 2000) = $160.14,

which is associated with a total cost = 160.14 * 10000 = $1,601,400

- weight method d2

The second approach considers only the effective generation at each bus:

zonal 2 = (20*9000 + 26*0 + 1000*1000)/10000 = $118,

total cost = 118 * 10000 = $1,180,000.

Comment

Based on the case study in Section 2.2.2 and Section 2.2.3, we can see that at different system situations (radial or network) and different market power situations, either nodal or zonal pricing system can result in higher total cost. One cannot make the conclusion that one is absolutely better than the other.

2.2.5 Nodal vs. Zonal Pricing

The similarities between zonal and nodal pricing far exceed the differences. Both methods are locational pricing systems, and both try to capture economic efficiencies by an appropriate pricing methodology. In the process, they help manage congestion. They both begin from the same types of network models and the same general methodologies. The main two differences are:

- The zonal model buses are deliberately grouped for the main (claimed) objective of market power reduction, greater liquidity, greater apparent simplicity and more apparent transparency. The fact that zonal pricing leads to less market power, greater transparency and greater liquidity is not universally accepted. There are valid claims to the contrary. However, in this report we are accepting *ab-initio* that a zonal pricing system has some advantages and is therefore worth using in certain cases.

- The zonal model does not rely on a "central market" that performs all computations for all the markets, although in effect the ISO becomes the market maker in a zonal model.

Debate about the zonal price vs. nodal price is ongoing. PJM uses the nodal pricing system to manage congestion, while CAISO uses zonal pricing system to manage congestion. The CAISO contends that zonal price is the right way to manage the congestion and reasonably utilize the resources.

Many researchers don’t agree with CAISO’s congestion management method. For example, by assuming that CAISO take the highest nodal price as the zonal price, Scott M. Harvey and William W. Hogan claim that there are at least four reasons nodal pricing

is superior to zonal pricing from a competitive standpoint when the potential for the exercise of locational market power exists:

> "*First*, zonal pricing can create market power in the hypothetical zonal dispatch that does not exist in the actual power market under either nodal or inter-zonal pricing. *Second*, zonal pricing can create market power in the zonal redispatch that does not exist in the actual power market under either nodal or inter-zonal pricing. *Third:* by reducing the response of demand in the constrained region to the exercise of locational market power, zonal pricing can make profitable the exercise of market power that would be unprofitable under either nodal or inter-zonal pricing. *Four*th, the zonal pricing and redispatch mechanism can reduce the supply elasticity of energy across open increases, making profitable the exercise of market power that would be unprofitable under nodal pricing" [3, 5].

After detailed analysis, they concluded that "in the choice between market pricing models based on nodal pricing that recognizes different prices at every location, and zonal pricing that creates administrative aggregations to reallocate costs, there is a nearly dominant answer. The result may appear counterintuitive, but nodal pricing is preferred for efficiency reasons and to mitigate market power" [3, 5].

The key assumption of Harvey and Hogan's work is the CAISO uses the highest nodal price in one zone as the zonal price. Actually, the CAISO now uses the weighted average nodal price method to calculate the zonal price. This may result in a reduction of market power, something that warrants further investigation.

IV CAISO Congestion Management

- The 5% Rule and Market Power Mitigation

This section reviews the CAISO congestion management method, and in particular, the so-called 5% rule [6, 7, 8, 9, 10, 11].

3.1 CAISO Congestion Zone Definition

The definition of congestion Zones is the cornerstone of every Zonal congestion model. A bad Zone definition may result in excessive loss of market efficiency and poor economic signals that may annihilate the benefits of applying locational pricing approach to congestion management through a Zonal model. The ISO uses a rigorous process for congestion Zone definition that is based on the following principles and assumptions.

1) Congestion within a Zone (Intra-Zonal Congestion) is infrequent and its associated cost over a certain time period does not exceed a specified threshold.

2) Congestion on the transmission interfaces between Zones (Inter-Zonal Congestion) is frequent and its associated cost over a certain time period exceeds a specified threshold.

3) Appropriate market power mitigation measures are in place where there is no workable competition within a zone.

4) The locational price dispersion within a Zone is small and can be ignored without significant loss of market efficiency. This is the case particularly when the system is truly radial, without mesh flows.

The congestion cost threshold in the first two principles is currently set at 5% of the transmission interface rating times the corresponding Transmission Access Charge over a year (5% percent rule will be discussed in detail later). The third principle, market power mitigation, represents a modification of the ISO's present Tariff provisions, which require that workable competition exist on both sides of a potential inter-zonal pathway in order to create a new active Zone. This proposal would relax the workable competition requirement and replace it with a framework for mitigating market power in the absence of a competitive adjustment bid market and competitive Zonal Ancillary Service and Zonal Imbalance Energy markets.

3.2 ISO Creation of Zones

The ISO creates Congestion Zones in accordance with the ISO Tariff. The following ISO Tariff sections describe the process and ISO requirements for establishing new Zones:

7.2.7.2.1 Modifying Zones. The ISO shall monitor usage of the ISO Controlled Grid to determine whether new Zones should be created, or whether existing Zones should be eliminated, in accordance with the following procedures.

7.2.7.2.2 If over a 12-month period, the ISO finds that within a Zone the cost to alleviate the Congestion on a path is equivalent to at least 5 percent of the product of the rated capacity of the path and the weighted average Access Change of the Participating TOs the ISO may announce its intention to create a new Zone. In making this calculation, the ISO will only consider periods of normal operations. A new Zone will become effective 90 days after the ISO Governing Board has determined that a new Zone is necessary.

7.2.7.2.3 The ISO may, at its own discretion, shorten the 12-month and 90-day periods for creating new Zones if the ISO Governing Board determines that the planned addition of new Generation or Load would result in Congestion that would meet the criterion specified in Section 7.2.7.2.1.

7.2.7.3.5 The determination of whether a new Zone or an existing Inactive Zone should become an Active Zone and the determination of whether a workably-competitive Generation market exists for a substantial portion of the year, shall be made by the ISO Governing Board, using the same approval criteria as are used for the creation or modification of Zones. The ISO Governing Board shall adopt criteria that define a "workably competitive Generation" market. The ISO Governing Board will review the methodology used for the creation or modification of Zones (including Active Zones and Inactive Zones) on an annual basis and make such change as it considers appropriate.

3.3 Active and Inactive Zones

In addition to the 5% criterion that was used to create the congestion Zones, another criterion was further used to determine if a Zone would be Active or Inactive. If workable competition is present on both sides of the Inter-Zonal Interface the Zone is active, otherwise inactive. The ISO presently has three active congestion zones: NP15, ZP26 and SP15. Both the San Francisco (SF) and Humboldt (HUMB) Zones were declared inactive due to lack of "workable competition."

The ISO mitigates congestion on inactive Inter-zonal interfaces by dispatching RMR units within the inactive Zones. RMR units within these Inactive Zones are typically dispatched to provide incremental energy after final Day Ahead schedules are submitted in order to ensure that sufficient generation within these Inactive Zones is on-line to ensure local reliability. The decremental costs of the units that are being decremented to accommodate the RMR resources are accounted for the imbalance energy market. This approach is similar to performing Intra-Zonal Congestion Management on the inactive Inter-Zonal Interfaces, with two key differences:

- First, the decision to dispatch RMR units is based primarily on the need to ensure local system reliability in the event of potential operating contingencies, rather than

the need to mitigate Intra-Zonal congestion that may exist each hour. RMR dispatches are also used to mitigate Intra-Zonal congestion over Inactive Inter-zonal interfaces.

- Second, RMR costs are not charged to the consumers in the Zone through the GOC, but are instead charged to the corresponding PTO. Therefore, these congestion costs are reflected in the PTO access fee paid by all users of the PTO transmission grid.

3.4 Definition of Inter-Zonal and Intra-Zonal Congestion Management

The ISO manages Congestion using a zonal-based approach. Transmission Congestion is divided into two categories:

1. Frequent and costly congestion with widespread effects, and

2. Infrequent and inexpensive congestion with localized effects.

The first category is referred to as inter-zonal congestion and primarily occurs on transmission interfaces between Congestion Zones. The second category is referred to as intra-zonal congestion.. Therefore, by definition and design, the transmission interfaces between Zones experience major congestion, whereas congestion Zones are network partitions that experience minor inter congestion. A congestion Zone is a portion of the ISO transmission grid within which transmission congestion is expected to be small and infrequent. Interfaces between Zones or Control Area boundaries, on the other hand, consist of paths that are expected to have relatively high Congestion Management costs. In this case it makes sense to allocate these Congestion costs to customers that utilize the congested paths and thereby send meaningful price signals to such users of the congested interfaces. Subsequent to the creation of the initial Congestion Zones, the ISO has continuously monitored all Congestion Management costs to determine if additional Zones should be created per the specified Zone creation criteria outlined in the ISO tariff. Congestion occurring on interfaces (also called "paths") between Congestion Zones is referred to as “Inter-Zonal Congestion.” Congestion due to network constraints within a Congestion Zone is referred to as “Intra-Zonal Congestion or AZCM..” Due to the different characteristics and economic impact of Inter-Zonal Congestion, they are treated differently by the ISO Congestion Management protocols.

3.5 Inter-Zonal and Intra-Zonal Congestion Management Methods

Transmission Congestion Management is performed sequentially for Inter-Zonal and Intra-Zonal Congestion, using different optimization methodologies and network models. Inter-Zonal Congestion Management is performed first, followed by Intra-Zonal Congestion Management. The ISO first makes use of the Scheduling Coordinators’ (SC) voluntarily submitted incremental and decremental Adjustment Bids in its Congestion Management protocols to adjust the Schedules efficiently. These Bids signal to the ISO the value that the SCs place on producing and consuming additional units of energy at different locations on the grid, and when taken together, the value of moving an additional unit of energy between locations.

3.5.1 Inter-Zonal Congestion Management Protocol

The Inter-Zonal Congestion Management is performed in the Forward Market (Day-Ahead and Hour-Ahead Market). The protocol is as follows:

- Inter-Zonal Congestion Management ignores Intra-Zonal constraints. These constraints will be taken into account during Intra-Zonal Congestion Management.

- Inter-Zonal Congestion Management uses a DC Optimal Power Flow (DC-OPF) and uses linear optimization techniques with only MW controls. This simplification enables reliable and robust calculation of meaningful transmission prices. The objective of the Inter-Zonal Congestion Management optimization problem is to minimize the net cost of redispatch, as determined by the SCs' submitted incremental and decremental Adjustment Bids. The objective function is equivalent to the net power generation cost objective used in the conventional OPF applications.

- Inter-Zonal Congestion Management adjusts Schedules to remove potential violations of Inter-Zonal interface constraints, minimizing the re-dispatch cost, as determined by the incremental and decremental Adjustment Bids that accompany the submitted Schedules.

- Inter-Zonal Congestion Management should not perform or execute trades between SCs. Each SC's portfolio should be kept in balance, i.e., its generation will match its load after adjustments. This is referred to as the "market separation rule". The philosophy behind this rule is that the ISO will adjust the Schedules for feasible operation without embarking on market decisions that can be and should be left with the Market Participants. The latter will have the opportunity to trade with one another and to revise their Schedules during the Congestion Management iteration in the Day-Ahead Market, and between the Day-Ahead and Hour-Ahead Markets.

- Inter-Zonal Congestion Management does not optimize SC portfolios within Zones (even if when patently non-optimal Schedules are submitted by SCs). Zonal adjustments to individual SC portfolios will be either incremental or decremental, but not both. Adjustment Bids can be submitted for import, export, generator, and load schedules.

- The incremental and decremental Adjustment Bids that the SCs submit constitute implicit bids for transmission between Zones. The ISO's Inter-Zonal Congestion Management protocol will allocate congested transmission to those users who value it the most and will charge all SCs for their allocated share of Congestion costs based on their use of congested transmission interfaces. All SCs therefore see the same price for transmitting Energy across a congested Inter-Zonal

Interface, irrespective of the particular locations of their resources and loads within the Zones.

- The ISO determines the prices for the use of congested Inter-Zonal Interfaces using marginal costs. The ISO collects Congestion charges from SCs for their use of congested Inter-Zonal interfaces. The Congestion revenues are allocated based on established rules, to the FTR Holders, TOs, and SCs that schedule in the opposite direction of Congestion on each Inter-Zonal Interface.

3.5.2 Intra-Zonal Congestion Management Protocol

At present, ISO does not perform Intra-Zonal Congestion Management if the forward markets but only in real-time. System operators manage Intra-Zonal in real-time by using RMR units, submitted bids, experience, and judgment.

Once the ISO determine where workable competition exists, real-time intra-zonal congestion is resolved by selecting bids out of sequence from either the imbalance energy stack or unused adjustment bids that were submitted in the forward markets. Where such workable competition does not exist, or if bids in workably competitive areas are insufficient to resolve congestion, the ISO may dispatch RMR units, or resort to the Out-Of-Market (OOM) protocol.

Resources participating in the competitive resolution of intra-zonal congestion are paid their incremental adjustment bid and charged their decremental adjustmental bid. RMR units are paid according to the RMR contract. Resources dispatched under OOM are paid the OOM price (ex-post price under abnormal conditions and as bid under normal conditions). The net cost of real-time Intra-Zonal congestion management is distributed evenly to all metered demand in the corresponding zone through the Grid Operations Charge (GOC).

ISO has proposed several Intra-Zonal Congestion management protocols. One method is to use AC OPF (Optimal Power Flow) to manage Intra-Zonal Congestion in the forward markets. This method is not currently used, and adoption of such approach will require development of the necessary software.

In the Zonal-Forward Market proposal, the process would be simplified. All Intra-Zonal calls in real-time would be paid based on the adjustment bid activity rules previously described for non-competition Zones. This process would not differentiate between RMR, OOS, or OOM, normal or abnormal conditions. For Zones with competition, all real-time calls are paid as bid with no cap. For resources that are critical to system reliability standing adjustment bids would be used if these resources do not participate in the forward transmission markets or the real-time imbalance energy market. With the proposed activity rules for adjustment bids, there would be no need for explicit RMR contracts or the OOM protocol.

3.6. The 5% Criterion

3.6.1 Introduction to the 5% Criterion

In the section "ISO Creation of Zones", the 5% criterion was introduced. The 5% criterion is a threshold for the accumulated Intra-Zonal Congestion Management costs on an Intra-Zonal interface over a period of 12 months. When these costs exceed the threshold, a new congestion Zone may be created.

The threshold is set to a specified percentage (5%) of the product of the Intra-Zonal interface rating and the weighted average of the relevant PTO access fees (The weights that are used in the weighted average are the percentages of ownership of each PTO on the Intra-Zonal interface). This product can be seen as the maximum transmission revenue from the specific Intra-Zonal interface, which would be collected if that interface were fully used throughout the 12-month period. Although the Operating Transfer Capability (OTC) is usually less than the rating of a transmission interface, the rating is used in the criterion because the OTC may vary considerably throughout the year. Therefore, the percentage criterion is the relative portion of the maximum transmission revenue collected from an interface that is considered significant to sacrifice simplicity in favor of market efficiency by promoting the interface to an Inter-Zonal Interface with the creation of a new Zone.

Table 1 is the Transmission Revenue Requirement (TRR) of the three PTOs for effective days in 1998 and 1999. The last column is a weighted average that represents the TRR for the first year of operations for the ISO, from April 1998 through March 1999.

PTO	Effective Day			1st year
	4/1/1998	10/30/1998	1/1/1998	
PG&E	$285,616,000	$315,811,000	$315,811,000	$298,273,082
SCE	$211,054,000	$211,054,000	$208,188,401	$210,347,414
SDG&E	$103,621,000	$103,621,000	$ 97,892,043	$102,208,380
TOTAL	$600,291,000	$630,486,000	$621,891,444	**$610,828,877**

Table 1: PTO Transmission Revenue Requirement

Table 2 lists the congestion revenues that were collected by the ISO on all Inter-Zonal Interfaces (only Day-Ahead Inter-Zonal Congestion Management) in the first year of operations and were paid to the PTOs.

Congestion revenues from the Hour-Ahead market were negative in the first 12 months of operations due to an anomaly referred to as the "TO debt". The TO debt scenario was

typically triggered after a reduction in the Available Transmission Capacity (ATC) of an Inter-Zonal Interface, e.g., due to a contingency, after the closure of the Day-Ahead market and prior to the Hour-Ahead market. In this case, PTOs were forced to buy back in the Hour-Ahead market unavailable transmission capacity that was previously sold in the Day-Ahead market. The transmission price was typically much higher in the Hour-Ahead market, and often hit the upper limit of the administratively set Default Usage Charge (DUC) of $250/Mwh because of the thinness of that market. This resulted in tremendous financial loss for the PTOs. In March 1999, this anomaly was corrected by requiring the PTOs to buy the derated capacity at the Day-Ahead price.

Month	Congestion Revenues
April, 98	$ 63,956
May, 98	$ 1,533,109
June, 98	$ 970,925
July, 98	$ 5,441,323
August, 98	$ 2,100,037
September, 98	$ 2,455,948
October, 98	$ 5,504,187
November, 98	$ 4,496,471
December, 98	$ 3,744,686
January, 99	$ 3,858,392
February, 99	$ 1,840,466
March, 99	$ 5,771,924
Total	$ 37,781,424

Table 2: Congestion Revenue by month

Table 3 lists the congestion revenues for the first 12 months of operations by Inter-Zonal Interface. It also lists the rated capacity of each interface.

Interface	**From Zone**	**To Zone**	**Capacity (MW)**	**Congestion Revenue**

COI	NW1	NP15	4,800	$ 10,832,478
ELDORADO	AZ2	SP15	1,557	$ 4,697,504
MEAD	LC1	SP15	1,460	$ 623,076
NOB	NW3	SP15	3,100	$ 4,338,598
PALOVRDE	AZ3	SP15	2,823	$ 5,186,983
PATH15	SP15	NP15	3,900	$ 11,878,656
SILVERPK	SR3	SP15	18	$ 22,953
SUMMIT	SR2	NP15	160	$ 11,899
SYLMAR-AC	LA1	SP15	1,200	$ 189,277
		Total	19,018	$ 37,781,424

Table 3: Congestion Revenue by Interface

To derive a benchmark for the 5% criterion, we have calculated a normalized yearly access fee (NYAF), by dividing the total TRR by the peak demand (44,927 MW) in the first 12 months of operation,

NYAF = $610,828,877/44,927MW = $13,596/MW

Then we calculated a Normalized Transmission Revenue (NTR) from the Inter-Zonal Interfaces where there was congestion in the first 12 months of operations, as follows:

NTR = NYAF * 19,018MW = $258,569,314.

Dividing the total congestion revenues collected in the first 12 months of operations by the NTR factor can derive a Normalized Congestion Cost Ratio (NCCR),

NCCR = $37,781,424/$258,569,314 = 14.61%

This percentage is the normalized congestion cost ratio of existing congestion and can be used as a reference point to evaluate the currently adopted threshold for the ratio of congestion costs over transmission revenue on a given interface. However, the congestion cost used in the 5% criterion is the Intra-Zonal congestion cost, not the Inter-Zonal congestion cost.

We need to further evaluate how the congestion costs relate under the two different scenarios: a) the Intra-Zonal scenario where the relevant interface is Intra-Zonal and congestion is mitigated using the Intra-Zonal Congestion Management protocols; and b)

the Inter-Zonal scenario where the relevant interface becomes Inter-Zonal and congestion is mitigated using the Inter-Zonal Congestion Management protocols.

When a transmission path previously designed as an Intra-Zonal interface is converted to an Inter-Zonal Interface, the original Zone that contained the interface is divided into two new zones, separated by the new Inter-Zonal Interfaces. The financial implications of this change on the marketplace depend on the structure of the SC balanced schedules and the division of supplies and demand resources within the new zones. The effects also depend on the direction of congestion. The financial impact of the zone division can be evaluated by comparing the costs to Market Participants (MPs) under the two scenarios: 1) Intra-Zonal congestion, and 2) Inter-Zonal congestion. The comparison is listed in Table 4.

	Intra-Zonal Congestion	Inter-Zonal Congestion
1	SCs are not charged explicitly for using the Intra-Zonal interface. It does not matter whether a SC is using the interface and in what direction.	SCs are charged explicitly for using the Inter-Zonal Interface in the direction of congestion, and paid explicitly for using the Inter-Zonal Interface in the opposite direction.
2	Congestion costs are calculated as bid and charged to all SCs pro rata on the demand (load and exports) in the Zone.	Congestion costs are calculated at marginal cost and charged or paid to all SCs using the interface depending on the direction.
3	PTOs do not receive congestion revenues and there is no impact on next year's access fees.	PTOs do receive congestion revenues that are reflected on next year's access fees.
4	Supply resources are paid the same Market Clearing Price (MCP) irrespective of their particular location in the zone.	Supply resources are paid different MCPs if they are located in different zones. Supply is paid usually less in the from-zone and more in the to-zone, compared to the Intra-Zonal case.
5	Demand resources pay the same MCP irrespective of their particular location in Zone Z.	Demand resources pay different MCPs if they are located in different zones. Demand pays usually less in the from-zone and more in the to-zone, compared to the Intra-Zonal case.

Table 4: Comparison of the Intra-Zonal and Inter-Zonal scenarios

In the analysis of financial impact of new congestion zones, somebody assumed that the bidding behavior of MPs will not change between Intra-Zonal and Inter-Zonal scenarios, i.e. SCs will submit the same Adjustment Bids under either scenario. This assumption is

reasonable for a highly competitive market since, in such an environment, the dominant bidding strategy is cost-reflective bidding. If there exists remarkable market power in the congestion management, this assumption can be challenged.

3.6.2 Case Study for Path 26

Path 26 was used as the study case. Path 26 is a recognized WSCC transmission path, and part of the ISO Controlled Grid, which consists of three parallel 500 KV transmission lines between PG&E's Midway and SCE's Vincent Substations. Both ends of path 26 were located within the SP15 Congestion Zone (South of Path 15). Therefore, path 26 was an SP15 Intra-Zonal interface.

During the first 12 months of the ISO's operation, Path 26 has been congested in the north to south direction for many hours. In these hours, ISO has managed congestion inn real time by increasing the output of resources south of Path 26 and decreasing the output of resources north of Path 26. Incremental and decremental adjustments were paid and charged as bid, respectively, according to the Intra-Zonal Congestion Management protocol. The congestion costs (net of payments minus charges) that the ISO has incurred in the first 12 months of operations are listed in table 5. Those costs are recovered from the demand through GOC (Grid Operating Charge).

Month	Congestion Hours	Congestion Cost
April 98	0	$ 0
May 98	45	$ 56,781
June 98	136	$ 1,692,991
July 98	103	$ 1,433,252
August 98	59	$ 742,033
September 98	0	$ 0
October 98	2	$ 4,745
November 98	0	$ 0
December 98	6	$ 173,031
January 99	5	$ 4,875
February 98	6	$ 82,181
March 99	36	$ 530,102

Total	398	$4,719,991

Table 5: Path 26 Intra-Zonal Congestion Costs

The maximum transmission revenue on Path 26 is calculated in Table 6.

PTO	Access Charge	Ownership	Rated Capacity	Yearly Cost
PG&E	$3.53/MWh	16.67%	500 MW	$ 15,461,400
SCE	$2.69/MWh	83.33%	2500 MW	$ 58,911,000
SDG&E	$6.82/MWh	0.00%	0 MW	$ 0
	Total	100.00%	3000 MW	$ 74,372,400

Table 6: Path 26 Maximum Transmission Revenue

One can find that for Path 26, the 5% criterion was met since the ratio of $4,719,991 over $74,372,400 equals 6.35%. Also, the second criterion that requires workable competition on both sides of a new Intra-Zonal Interface in order for a new Zone to be an Active Zone also holds for Path 26. As the result, in August 1999, the ISO Governing Board directed the ISO to create a new congestion Zone between Path 15 and Path 26 by converting Path 26 to an Inter-Zonal Interface so that congestion on Path 26 becomes Inter-Zonal congestion and priced at marginal cost according to the ISO Tariff. The new Zone is referred as “ZP26” and became effective at the same time with the Firm Transmission Rights (FTRs), for the trade day 02/01/2000.

Table 7 shows how these demand Zones map to the existing and new congestion Zones.

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Demand Zones	Congestion Zones	
	Before 02/01/2000	After 02/01/2000
PGE1	HUMB	HUMB
PGE2	NP15	NP15
PGE3	SF	SF
PGE4	SP15	ZP26
SCE1	SP15	SP15

SDG1	SP15	SP15

Table 7: Demand Zone Mapping to Congestion Zones

The objective of the case study is to compare the actual congestion costs that were incurred by performing Intra-Zonal Congestion Management on Path 26 in real time with the congestion costs that would have been incurred should Path 26 were an Inter-Zonal Interface in the first 12 months of operations. Inter-Zonal Congestion Management simulations were performed by ISO, using the historically submitted schedules and bids, but on a modified network model where Path 26 is an Inter-Zonal Interface and ZP26 is defined as a separate congestion Zone. The simulations were performed only for the Day-Ahead market, since the volume and activity in the Hour-Ahead market were very small in the first 12 months of operations. Furthermore, the simulations were limited to the hours where Path 26 was congested according to the submitted schedules and the estimated OTC of the path. The estimated OTC of the path was calculated based on the ATC of path 26 and certain assumptions about the transmission capacity usage and reservation on behalf of Existing Transmission Contract (ETC) right holders. The congestion on Path 26 was present only in the southbound direction. The ATC on path 26 is 2600 MW in that direction, which is considerably lower than its WSCC rating of 3000 MW. The simulation results showed that after elevate Path 26 from Intra-Zonal to Inter-Zonal Interface, the total congestion revenue of ISO increased by $24,470,001, the congestion revenue on Path 26 increased by $22,709,738. This Inter-Zonal congestion costs for Path 26 are several times more than the Intra-Zonal congestion costs that were actually incurred on Path 26. But this should be viewed as the upper bound of possible values since it is very likely that bidders will modify their bidding behavior to self-manage congestion. Dividing the $22.7 million by the Path 26 maximum transmission revenue of $74,372,400 (shown in Table 6) results in a congestion percentage of approximately 30%, which is above the congestion percentage of 14.61 for the existing Inter-Zonal Interfaces. This suggested that use of the 5% criterion leads to results that are consistent with congestion experiences on the existing Inter-Zonal Interfaces.

3.6.3 Conclusions on Zone Creation Criteria

The basis for the analysis of the Zone creation criteria is the comparison of congestion costs to transmission revenue, for a candidate Intra-Zonal interface. This ratio is compared to the ratio of total congestion revenue versus normalized transmission revenue from all existing congested Inter-Zonal Interfaces. The latter ratio or congestion percentage is used as a reference point to assess the results of using the 5% criterion. If the congestion percentage for a transmission path that has been elevated to an Inter-Zonal Interface is equal to or above the reference point congestion percentage of 14.61% for the existing Inter-Zonal Interfaces, the estimated congestion on the new Inter-Zonal Interface is consistent with the congestion for the other, existing Inter-Zonal Interfaces. Consequently, this is an indication that use of the 5% criterion is reasonable and that the interface should be treated as an active Inter-Zonal Interface, if it also meets the second criterion of having workable competition on both sides of the interface.

A case study of Path 26 congestion mitigation with Path 26 being an Inter-Zonal Interface shows that the congestion costs under the Inter-Zonal scenario are several times greater than the congestion costs under the Intra-Zonal scenario. However, these Inter-Zonal costs should be viewed only as the upper bound for the congestion costs that would have occurred since MPs are expected to react to the economic signals by altering their bidding behavior and schedules.

In the future, ISO will provide more frequent monitoring of congestion cost accumulation and more insight in the determination of appropriate criteria for Zone creation. New Zones would not be created more frequently than once a year, because of the yearly term of FTRs, but the decisions, and necessary network and system changes for new Zones can be made in advance.

3.7 Market Power Mitigation

Market power mitigation is an essential element of the Zonal-Forward Market proposal. No congestion management reform proposal will be successful without addressing market power issues. These issues includes:

1) Lack of workable competition in a Zone that otherwise meets all other congestion Zone creation criteria.

2) Submitted adjustment bids for either inter-zonal or intra-zonal congestion management from resources with the potential of exercising market power due to their location or abnormal system conditions, and

3) Lack of submitted adjustment bids (capacity withholding) from resources that are critical for the reliable operation of the system.

3.7.1 Workable Competition Assessment

The ISO has developed a general procedure to determine whether the market in a particular area is workably competitive. The classical economic definition of a workably competitive market is one in which enough firms compete to produce the same product such that no one firm is able to raise prices significantly above system marginal costs for a sustained time period. Market power exists if there is the ability to raise prices significantly above system marginal costs unimpeded by competition from other suppliers, substitute products, or demand elasticity. A workably competitive market produces market prices that are reasonably close to system marginal cost (i.e., the highest cost unit required to serve the demand).

With this definition, the main indicator of market power would be the degree to which prices exceed the marginal cost of the highest-cost unit required to serve the demand. In practice, there is no one threshold for this measure that clearly differentiates between

competitive and non-competitive conditions. As s result, assessment of workable competition relies on a number of qualitative indicators, including:

- Significant supply quantity bid into the market above the current market-clearing price;
- Bids at or near marginal costs;
- Absence of concentration of supply (as measured by market shares, HHI indices, and Residual Supply Indices (RSI), for example); *(HHI is a market concentration index calculated by taking the market concentration of each company, squaring it, and summing up all squared values. The higher the HHI, the more concentrated the market. An HHI of 2000 is often viewed as a moderately risky market condition);*
- Demand flexibility or elasticity;
- Absence of institutional barriers to rivalry among suppliers or demand flexibility;
- Difficulty of collusion;
- East of entry of additional supply to the market.

Based on these considerations, the ISO employs the following three-step approach to assess the competitiveness of markets.

1. Define the markets: the relevant geographic boundaries, the products, and the relevant supplies. The boundaries of the markets typically depend on the availability of transmission facilities and the congestion conditions. This step must consider the frequency of each market condition. Regarding the products, competitiveness must be assessed for all products that will be procured zonally, including ancillary services and real-time energy as well as competition for the use of the congested inter-zonal pathways.

2. Screen for workable competition in each relevant geographic and product market defined in step 1 above. Markets that fail to pass the screen or are borderline would then be subject to step 3.

3. In-Depth Study of Market Power

   A market that does not pass the workable competition screen in step 2 must be subjected to further scrutiny, with a primary focus on the economic impacts of market power (i.e. the extent to which the exercise of market power can raise prices above system marginal costs).

3.7.2 Adjustment Bid Activity Rules

The following adjustment bid activity rules address market power issues in Zones where is no workable competition. These rules would also apply if necessary to mitigate market power in intra-zonal congestion even if the Zone is deemed workably competitive for inter-zonal congestion and other ISO markets. Until workable competition in the zone as discussed in the previous section is achieved, or we reach a pre-specified sunset date after the Zones is created, the following rules will not be enforced. A periodic analysis would be performed taking into account changing conditions within Zones, including the development of load responsiveness.

1. Adjustment bid caps would be defined for all resources within a congestion Zone that does not have workable competition.

2. Adjustment bid caps would be defined for all resources with the potential of exercising market power in intra-zonal congestion management, or for reliability needs due to their location, both in forward and real-time markets, and under both normal and abnormal conditions.

3. The transmission across inter-zonal boundaries would still be priced based on the second-price auction (i.e., marginal bid pricing) methodology. A resource with an active bid cap can set the price; if it does not set the price, it will be paid the market-clearing price set by the highest priced unit dispatched in the congestion region in which it is located.

4. Standing adjustment bids with bid caps would be used for resources within congestion Zones that do not have workable competition if these resources do not voluntarily submit adequate adjustment bids.

5. If the congestion regions are competitive for inter-zonal congestion management, but the intra-zonal congestion management is non-competitive, bid caps would become active only for intra-zonal congestion management. This would mean that bid caps would apply only to that portion of the unused adjustment bids in which the bid price exceeds the bid cap.

The adjustment bid caps would be resource-dependent and could be the verifiable variable costs for the resource plus a relative adder (e.g. 10-20 percent) to cover fixed costs and provide a strong incentive for generation expansion in the problem area. The need for bid caps for Intra-Zonal Congestion Management (AZCM) is illustrated by two congestion gaming practices that were identified by FERC as exemplifying a major flaw in the ISO's current congestion management approach. These practices are known as the "DEC Game" and the "INC Game".

The DEC Game

There exists a gaming potential in the AZCM decremental bid market that is exacerbated by the lack of workable competition. A generator with locational market power can schedule in the forward market so as to create intra-zonal congestion and then submit a

highly negative decremental bid to alleviate it, thus making huge profits if the ISO has no option but to accept its bid.

The INC Game

In the absence of a competitive market, a similar game may be played with incremental bids. A generator in a load pocket can under-schedule in the forward market so as to cause intra-zonal congestion, and submit very high incremental bids to alleviate it.

Both DEC game and INC game show that the necessary of the bid caps for ISO's Intra-Zonal Congestion Management (AZCM).

3.8 Summary

In this section, the CAISO zonal management methods are studied. Congestion zone management is a complicated problem, which involves the generation capacity of generators, transmission capacity, forward market and real-time market involvement, zonal or nodal model, and much more. The Congestion zone definition, Intra-Zonal and Inter-Zonal congestion management, 5% criterion, and the market power mitigation in the congestion zone management are discussed in detail in the report.

How to find the Zonal price is not discussed here. Currently, the weighted average of the nodal price is assumed to be the zonal price. It is debatable whether this zonal price definition method is the best way. This remains to be a problem to be solved. The overall coordination of the market under proposed zonal management method is not discussed in this report. Problems such as Long Term Grid Planning, Market Separation, Market Transparency, etc. need further study

One question remains is that is 5% criterion the only way or the best way to create the zones. The answer is that much research is going on and some new zone creation methods have been proposed. The next section of this report proposes a new methodology for automatic zone creation/merging/partition.

IV Methodology for Automatic Zone Creation/Merging/Partition

4.1 Introduction to the Methodology

When congestion occurs in a path that completely splits two parts of the system, determination of zonal prices is trivial: each zone has its own unique zonal price. Many "paths" are part of nomograms and the limits on these paths are a function of the flows on the individual path components. In a few cases, as for example in the case of paths that represent stability limits, the variable that is constrained is the sum of powers in across the path lines. In other cases, nomograms define more complex functions of these flows as constraining elements. In almost all cases, however, a path does not completely split

the system unless external loop flows are ignored. Path constraints that rely on stability or other such "sum of all cutset flows" limits tend to produce good but not complete system separation. On many cases the limits are not on an entire "cutset" path but on one or more path components or on some combination of the individual path flows, perhaps augmented with some voltage or other such limits. Under these conditions, there can be a great deal of price dispersion possible among individual nodes in the network. There may be a continued desire to still use the notion of a path that splits the network and thus retain the notion of unique zonal prices. However, it is of interest in this project to *not* start from this presumption but to allow individual lines or arbitrary combination of lines to become congested. Only after individual nodal prices are determined, and starting from these disperse zonal prices zones are defined. After zoned are defined, zonal prices can be subsequently determined by aggregation.

In order to determine nodal price dispersion we will require the following information:

- Network information, from which PTDF's (Power Transfer Distribution Factors) can be computed.

- The location of each and every congestion incident.

- The locations of units that can be used for redispatch whenever congestion occurs.

Observe that it is *not* necessary to have bid prices, flow limits or even flows in order to do what we intend to do. While this additional information would be helpful in refining the results (particularly when one tries to do zonal aggregation or one tries to predict future congestion patterns and future prices), this is not required for the analysis in this document.

The proposed methodology functions as follows:

- Potentially congested lines are identified as follows: (a) every line that is part of a path definition, and (b) any line that has congested at some time in the past leading to the need for redispatch.

- Potentially marginal generators are identified as any generator that (a) routinely submits inc and dec bids, (b) has participated as part of prior RMR conditions, (c) is part of the OOM set, or (d) is part of the OOS set.

- For every individual potentially congested line (as defined above), one or more pairs of redispatchable units are identified from among the generators chosen above.

- Using these lines and locations, the appropriate PTDFs is determined for all system locations and for the lines that can potentially congest.

- For every marginal generator pair selected, a set of price differentials will be assumed for the redispatch. When no other information is available, it will be assumed that there is a 20% price differential between the two units, arranged as a ±10% from the

base price conditions. (Note: the results are largely independent of this assumption, in that the assumption amounts to nothing more than a scaling of the price difference patterns that result).

- Using these units as new marginal units in the system, pseudo-nodal-prices are computed for every node in the system. These prices will be the nodal price departures from the base price at every node.

- If the prices observed are neatly divided into two values, the network has been split and the path has been identified. Otherwise, the largest price differential across any line pair is identified. An important by-product of this step will be the "price spread" within each zone.

- If the system has not been completely split, the prices observed are classified into two or more (but not exceeding 20) price "bands" and zones are defined. The maximum number of zones defined by any one constraint is generally much lower than this number of 20.

- After this has been done, an investigation of possible mergers and consolidations of zones can be performed for all those cases where trivial zones are identified (either very small zones, or zones that did not lead to significantly different prices from other zones under most or all conditions).

4.2 Case Study on Path 26

As shown in Section 3.6.2, Path 26 is a recognized WSCC transmission path, and part of the ISO Controlled Grid, which consists of three parallel 500 KV transmission lines between PG&E's Midway and SCE's Vincent Substations. Both ends of path 26 were located within the SP15 Congestion Zone (South of Path 15). Therefore, path 26 was an SP15 Intra-Zonal interface.

Section 3.6.2 showed that by using 5% rule, CAISO has separated the original zone SP15 to two zones (ZP26 and new SP15). In this case study, we consider the original SP15 zone, then Path 60 is the intra-zonal congestion line in original zone SP15. By using the methodology proposed in this report, we will come up with a new zone breakup result.

First, we suppose all the buses in zone SP15 have zonal price $100. When congestion happens, the bus with lowest PTDF has nodal price of $80, the bus with highest PTDF has nodal price of $120. After implemented the zonal breakup method, Figure 1 to Figure 6 show three pairs of figures.

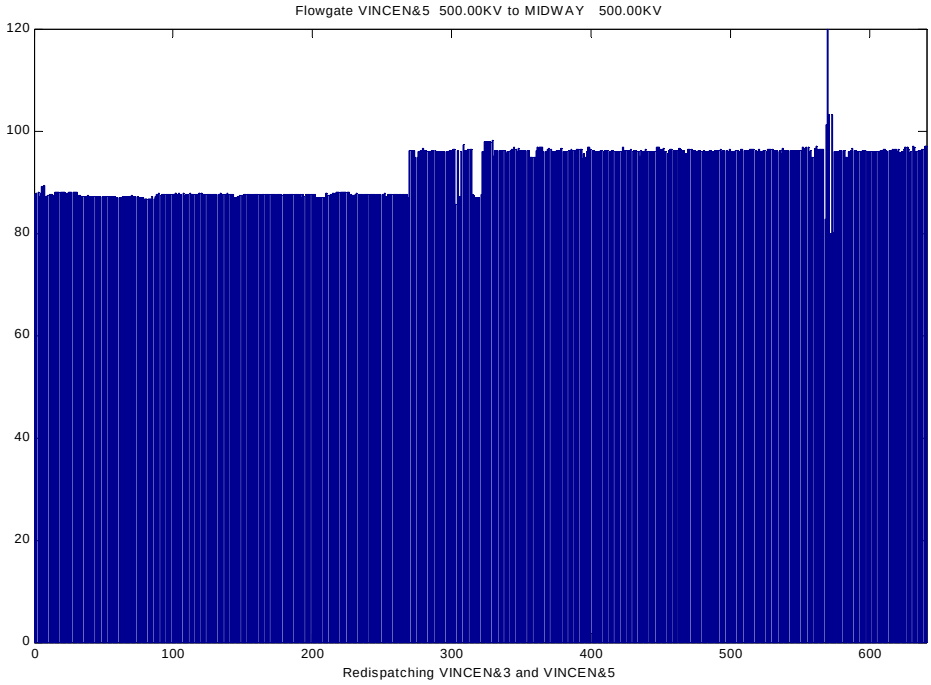


Figure 1. Nodal price pattern for flowgate from bus “Vincen&5” to bus “Midway”

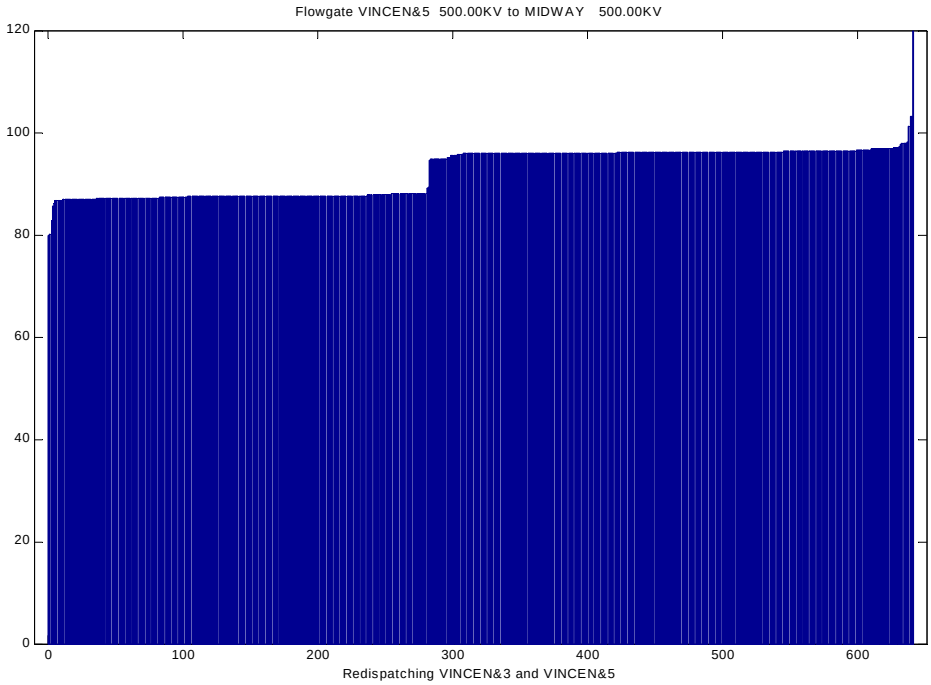


Figure 2. Sorted nodal price pattern for flowgate from bus “Vincen&5” to bus “Midway”

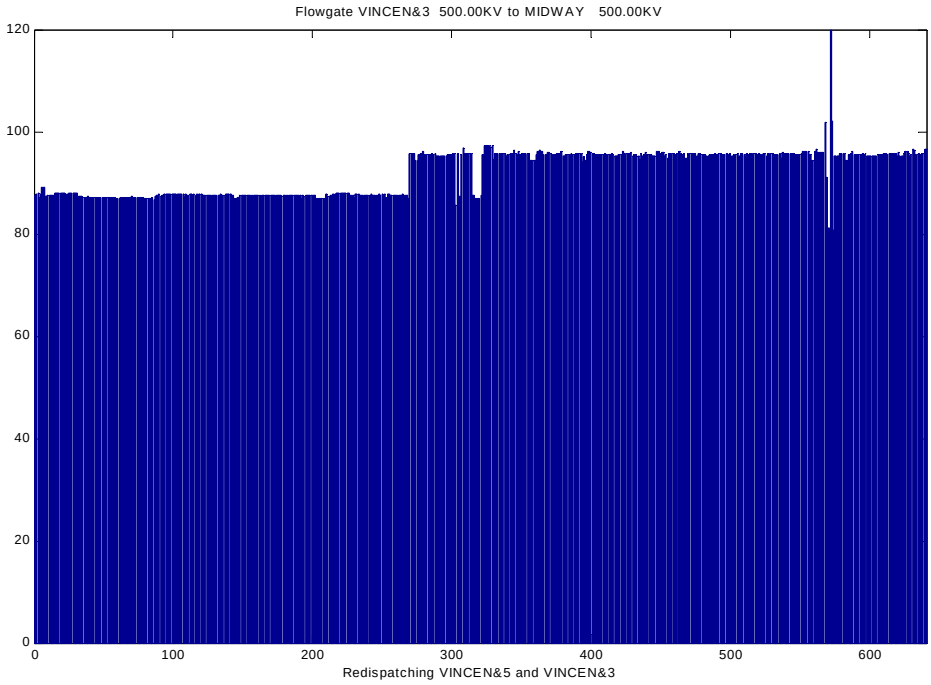


Figure 3. Nodal price pattern for flowgate from bus “Vincen&3” to bus “Midway”

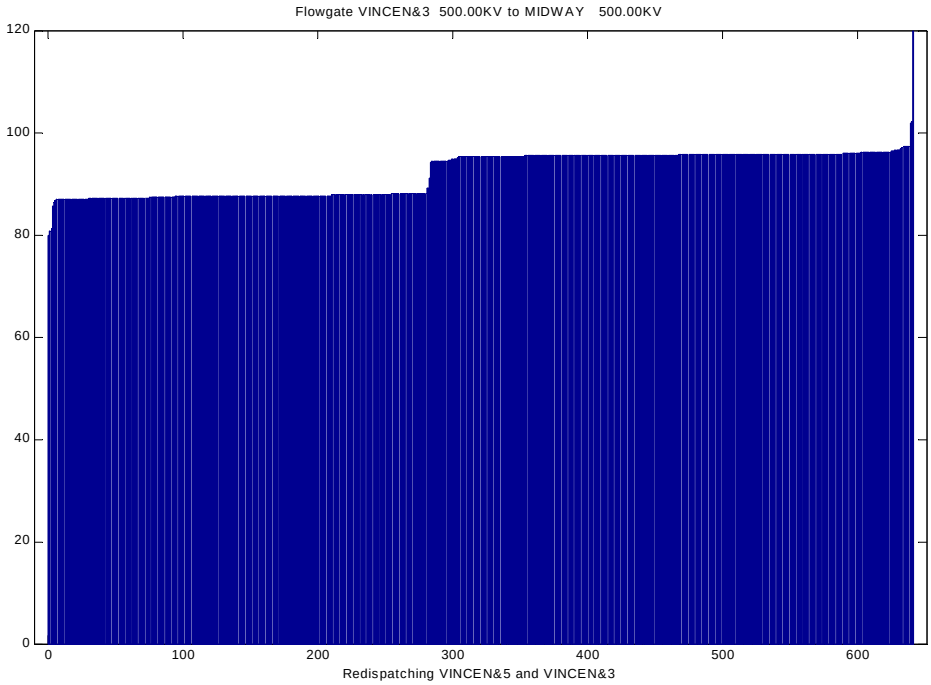


Figure 4. Sorted nodal price pattern for flowgate from bus “Vincen&3” to bus “Midway”

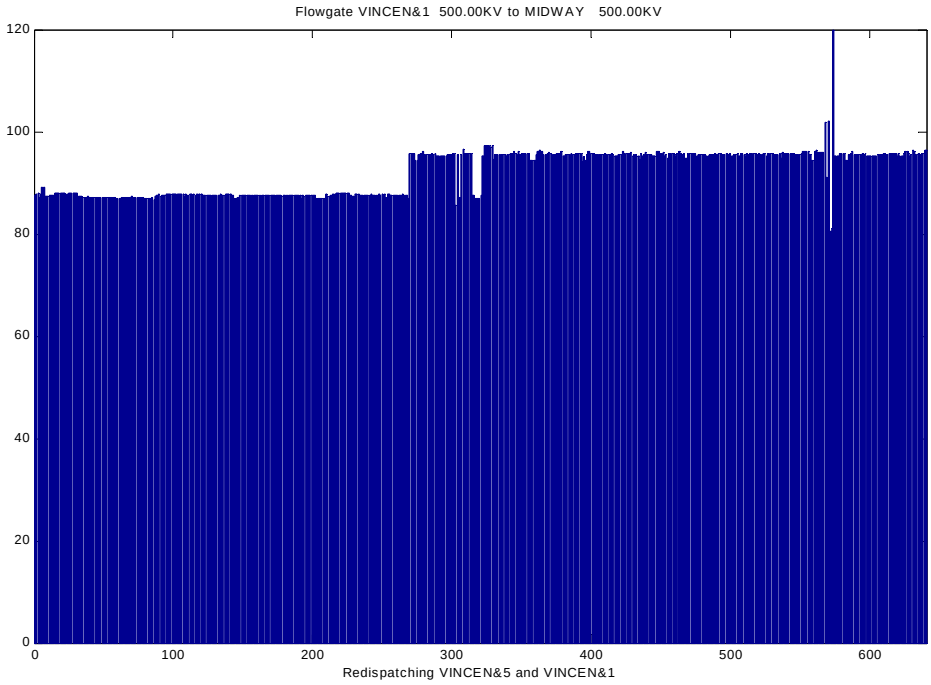


Figure 5. Nodal price pattern for flowgate from bus “Vincen&1” to bus “Midway”

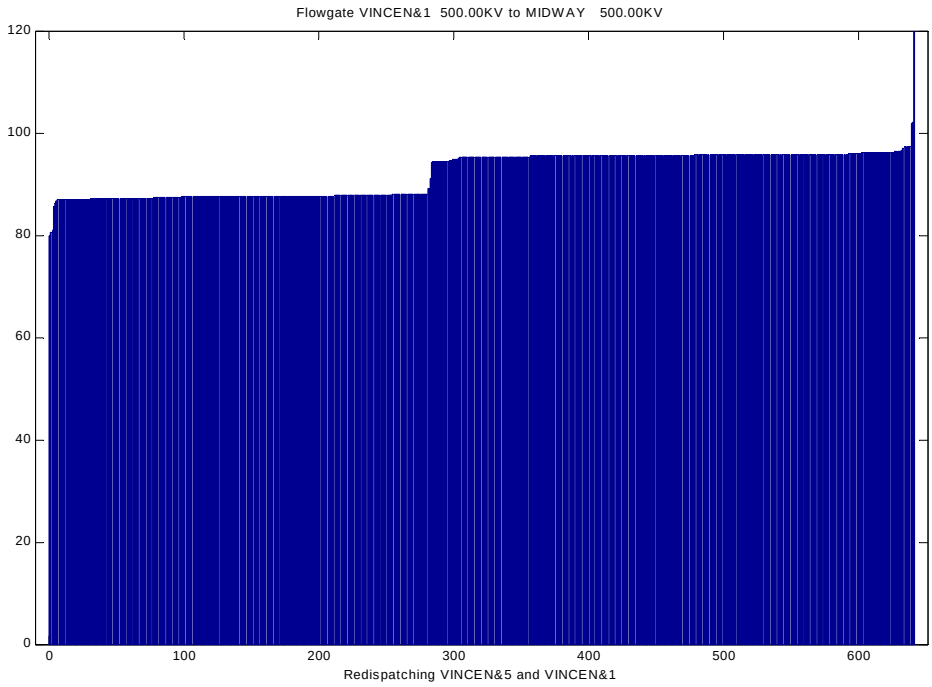


Figure 6. Sorted nodal price pattern for flowgate from bus “Vincen&1” to bus “Midway”

It is obvious that the price patterns for the three lines of PATH 26 are very similar. The buses can be distinctly separated to two zones.

One can see that based on this method, the zonal separation is VERY SIMILAR to the CAISO result based on 5% rule. One new zone very much like new ZP26 zone, the other new zone very much like the new SP15 zone.

4.3 Illustration of the methodology for the California System

For the case of California, there are a number of identified constraining paths. In addition, the system limits are expressed as “nomograms” that determine feasible operating regions. The nomograms are merely graphic expressions of some limit that has been “mapped” into a smaller set of constraints on readily measurable variables such as voltages, flows, sums of flows, levels of nodal generation or some such measurable quantity. For the purpose of this report, we will assume that all nomograms can be expressed as a finite set of limits on linear functions of flows. More specifically, we will illustrate the limit for each and every path component. We will also illustrate the case of a limit on the total path power. However, it is straightforward to extend the method to consider nonlinear functions of these flows, alone or in combination. It is also possible to include power injection or extraction at any node, to add reactive powers and voltage magnitudes, or any other desired system quantity of importance from any nomogram. The fundamentals of the method for zone determination are not affected.

For the examples in this report, all paths in the California system have been decomposed into their constituting components. In addition to considering every line in every inter-zonal path as a possible congesting facility, we also consider the possible inter-zonal congestion based on prior reports of what has congested where that has required either invoking RMR, OOS or OOM redispatch.

The specific results are illustrated in the appendix. For each of these cases, we illustrate the following:

1. A picture showing the exact nodal prices when the particular line congests and a particular generator pair is selected for redispatch. Important: the main results are NOT sensitive to the choice of redispatch generation pair. To illustrate this point, we also show the nodal price pattern that develops if a less effective generation pair is randomly chosen. This clearly demonstrates that, although the individual prices vary according to this choice, the price pattern that develops does not. This is a direct consequence of the Chao and Peck results [12], where nodal prices are seen as nothing more than a mapping from the shadow price across the congested facility as they get mapped to the individual nodes.

2. A picture illustrating the price differential across all the lines in the system. The biggest price differential should always be across the congested facility (or across a line directly in parallel with the congested facility).

3. A sorted plot of all nodal spot prices classified by color according the zones selected by our zone partitioning algorithm.

4. A map of California illustrating (using colors) the various zones implied by the zone-partitioning algorithm.

We will now illustrate a number of cases. The individually congested lines have been selected from among those that form part of cutsets (paths) as defined by the CAISO. We also plan to add to this mix several of the lines that have required redispatch in the past but are not part of the existing paths (those lines that have created the need for intra-zonal out of merit redispatch). At a later stage we will also illustrate notions of zonal aggregation and compare the zones that come out of this methodology with the existing zonal structure in California. Next, we intend to extend the methodology to consider multi-line paths (when the limit is truly on a path, not on a line) up to and including a complete cutset path. We intend to show how the proposed method does in fact give the same results that are presently in use by the CAISO. Finally, we also intend to illustrate the possible effect of loop flows outside of the California system on these prices. However, because of the extensive use of PARs (Phase Angle Regulators, a.k.a. Phase Shifters) and other such technologies, such loop flows are not expected to have a large impact on zone definition at this time. Nevertheless, we intend to study such effect.

For this report we consider the following examples:

- A simple case of intra-zonal congestion that results in well-defined zones.

- A case of intra-zonal congestion that results in "hot spots," that is, locations in the system with drastically different prices than other surrounding locations.

- A case of inter-zonal congestion.

At present, only a few cases are shown. By now, however, we have similar results for over 100 cases. The situation of multiple congested lines is still under implementation. To start this discussion, we first illustrate the present Area and Zone structure as specified in the Power Flow data received from the CAISO.

The cases that follow are divided into "path" or "nomogram" congestion cases, and "intra-zonal" cases. For each of the "path" cases, we illustrate the following:

- The case of every path or nomogram *component* congesting independently.

- The case of the sum of flows congestion in all components congesting.

For the case of intra-zonal congestion, only the patterns resulting from the individual component congestion are illustrated, since these congested lines are not part of a nomogram or existing path.

For each of these cases, the following pictures are shown:

- The price pattern that develops when each and every component of the path or nomogram becomes binding.

- The sorted pattern or price differences across the 50 most significant lines (how many lines or transformers show large price differentials).

- The sorted pattern of prices, classified by zone according to our method, and color-coded.

- The resulting zonal pattern in the map.

The vertical scales are not significant except in relative terms. However, when values of price differences are much greater than 1 this is an indication that the available generators had difficulty coping with the congestion by means of generation redispatch. In cases where there is a single effective generator location, this can be interpreted as a degree of local market power.

4.4 General Observations and Conclusions

The results from the studies in the appendix lead to a number of observations and conclusions.

- The location of the generating units has little to do with the resulting zonal pattern that results (although changing the location of the marginal generating units can lead to much higher price differentials, the patterns stay fundamentally the same).

- In some cases crisp well-defined zone boundaries occur. However, in other cases the boundaries are not that crisp.

- In general, intra-zonal congestion did not result in good zone separation. Intra-zonal congestion when the sum of the power across the path is congested often led to a reasonable zonal structure except for the common presence of frequent "hot spots."

- These hot spots correspond to locations that are exceedingly important in mitigating the specific congestion condition. Many but not all the studies had hot spots to some degree. In some cases, hot spot locations correspond to a single bus.

- The existence of hot spots is not dependent on the location of available generators. It is a property of the network itself.

- Even when an entire path that presumably separates the system, significant price dispersion remains as a result of flows in the external system.

- The best organization of zones is not always according to pure geography, but according to electrical connectivity and topology. In some cases better zones are created when some high voltage buses that are geographically within one zone are actually placed in a different zone.

4.5 Comments on Specific Paths and Flowgates

- Congestion on some path 15 components leads to zones that are not well defined and vary widely depending on the component. For some components, such as GATES to HENRETTA, good zonal separation develops. Congestion of the total path flow leads to a better but imperfect separation of the system into two reasonably well-defined zones with some "hot spots."

- Congestion of either line to CFE results in clear separation of markets

- Paths 26 and 44, when they congest on the total sum of powers condition, lead to reasonably crisp zonal separation of the system.

- Congestion into the Fresno area assessed as the sum of total imports leads to a relatively well-defined zone separation of the system into two zones. However, if some of the limits are surrogates for voltage problems a different and less crisp picture might evolve.

- Intra-zonal congestion in some paths such as Humboldt or some intra-zonal congestion such as GRIZ to Caribou leads to highly localized effects that do not propagate far into the system.

- Other cases of intra-zonal congestion lead to much less crisp potential zonal boundaries.

4.6 Recommendations

Based on these studies, we are prepared to issue some preliminary recommendations regarding the creation and aggregation of zones for the CAISO:

1. The establishment of a zonal structure should be based not on geography but on the detailed analysis of price *patterns*. The use and knowledge of precise prices is neither necessary nor desirable, as it would lead to zonal structures that depend on generation rather than network properties.

2. The price patterns should be established based on prevailing and anticipated congestion patterns as determined by existing or new operational procedures that assure system security. Those procedures deemed at present too complex for direct incorporation into the methodology will require further analysis to "translate" them into meaningful and practical measures in terms of limits on traded quantities or combinations of traded quantities.

3. While in many cases a zonal structure can be used. However, because of loop flows, it is recommended that there be a means of pricing non-contiguous transactions. The use of either direct (flowgate based) or indirect (in this case zonal) pricing should be adopted, with the realization that the direct flowgate pricing method will require the need of creation of portfolios of rights to put together transaction between any two zones (even when the zones are contiguous). The indirect method should have no such restriction, but may lead to a need for centralized clearing of transactions. (Note: the author of this report believes that a decentralized – or at least an instantaneous centralized – clearing process can be developed and should be investigated.)

4. Zones should not be based entirely on geography but rather on the electrical characteristics of the network itself.

5. A zonal structure established according to the terms above should be sufficient for most needs. However, the studies in this report suggest that the presence of "hot" (or "cold") spots (that is, locations that have a marginal price that is significantly above or below the otherwise zonal value) need to be recognized. Thus, a "zonal plus hot spots" approach to zonal pricing is recommended. If using prices to induce or restrict operation at these hot spots is rejected, then a means for dealing with these "hot spots" by regulatory means needs to be developed.

6. There should be an effort undertaken to try to go back to basic principles in the establishment of operational limits. Nomograms created for an era of regulated operation when computing and modeling capabilities were limited should be gradually replaced with new nomograms and other ways of expressing system limits based on actual modern system operational practices. These limits should be based on properly agreed upon reliability criteria and should be expressed in a manner sufficiently accurate but also sufficiently simple for the market to take into consideration when making trading decisions.

It is clear at this point that incorporating any nomogram, no matter how complex, should be a fairly straightforward task for this methodology. Appendix B illustrates a sampling of the main nomograms presently in use by the CAISO.

V Conclusion and Future Work

The congestion management of modern power system is a very complicated problem, it involves the physical structure of power system, the financial situation and strategy of the customers, etc., and even the government policy may have deep effect.

This report first summarized the widely used zonal and nodal pricing system in the power system, then discussed the zonal management method used by CAISO, finally proposed a new zonal breakup methodology and gave case studies of this method. Several conclusions can be reached:

- The similarities of Zonal and Nodal pricing system are more significant than the differences. One cannot say one system is more cost-effective than the other, this totally depends on the particular system structure and local power generation cost.

- 5% creation and market power mitigation method used by CAISO is working but still need improvement.

- The methodology proposed in this report gives a new view of how to breakup zones and perform zonal congestion management

There is still a lot of work need to be done:

- Improve the new methodology, try to improve the creation of zone breakup, make this methodology more practical.

- Further evaluate 5% creation and CAISO market power mitigation method.

We hope we can find a new and reasonable congestion management method in the near future.

References:

1. Ziad Alaywan, “Facilitating the Congestion Management Market in California”, California Independent System Operator, April, 1999.

2. California Independent System Operator Corporation FERC Electric Tariff.

3. Scott M. Harvey and William W. Hogan, “Nodal and Zonal Congestion Management and the Exercise of Market Power”, January 10, 2000.

4. California Independent System Operator Corporation, Department of Market Analysis, " Response to 'Nodal and Zonal Congestion Management and the Exercise of Market Power'", Federal Energy Regulatory Commission, Docket No. ER00-703-000, January 27, 2000, pp. 16-20.

5. Scott M. Harvey and William W. Hogan, " Nodal and Zonal Congestion Management and the Exercise of Market Power: Further Comments", report available in Hogan's homepage, made available on February 11, 2000

6. “Comprehensive Congestion Management Reform ‘Zonal-Forward Market’ White Paper, April 2000, CAISO, Draft for public release.

7. “Congestion Management Methodology: Principles, Models and Examples – In Support of the Congestion Management Reform Project”, Appendix B of Reference1April 2000, CAISO, Draft for public release.

8. “California ISO Zone Map: Effective Feb. 2000”, CAISO, www.caiso.com

9. “California Independent System Operator Corporation FERC Electric Tariff”, CAISO, www.caiso.com

10. “Report to the Federal Energy Regulatory Commission: Studies Conducted Pursuant to the October 30, 1997 Order”, CAISO, www.caiso.com

11. “ISO Creation of Zones”, CAISO, caiso.com

12. Hung-Po Chao and Stephen Peck, “A Market Mechanism for Electric Power Transmission,” *Journal of Regulatory Economics*, Vol. 10, 1996, text, pp. 44-46.

APPENDICES

Areas and Zones of the California system "as received"

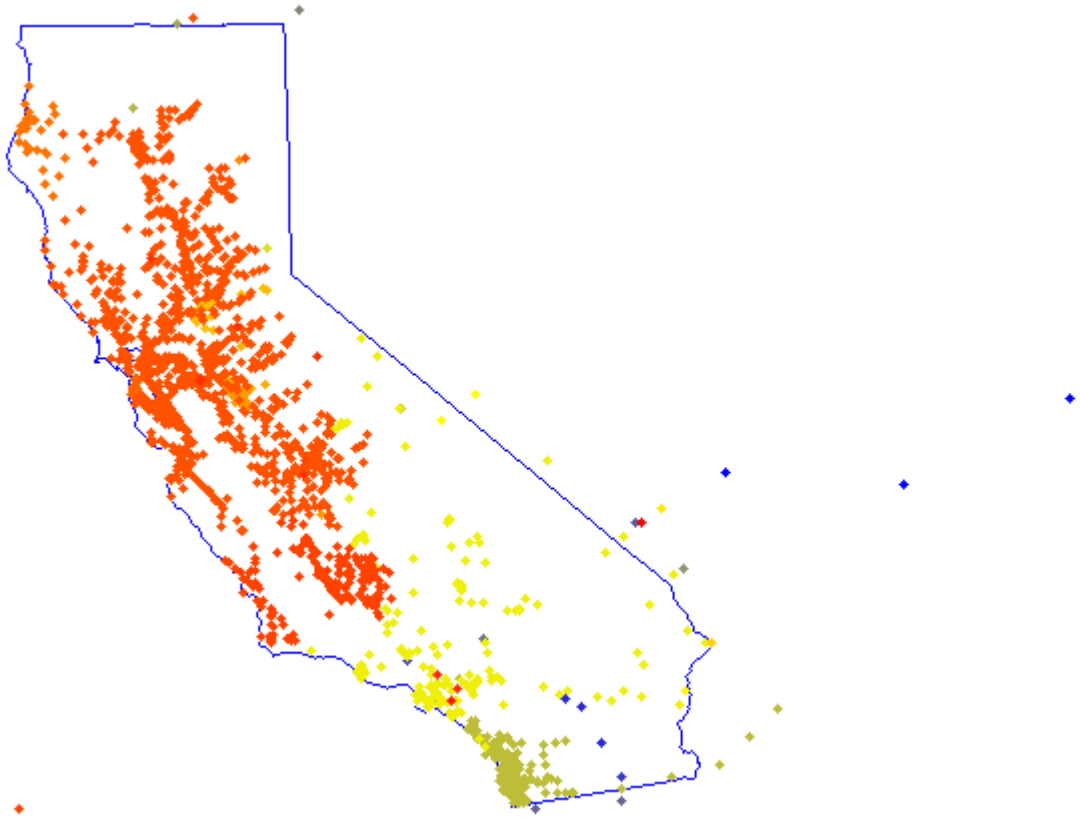


Figure 1: Area structure for present California system. Areas are color-coded.

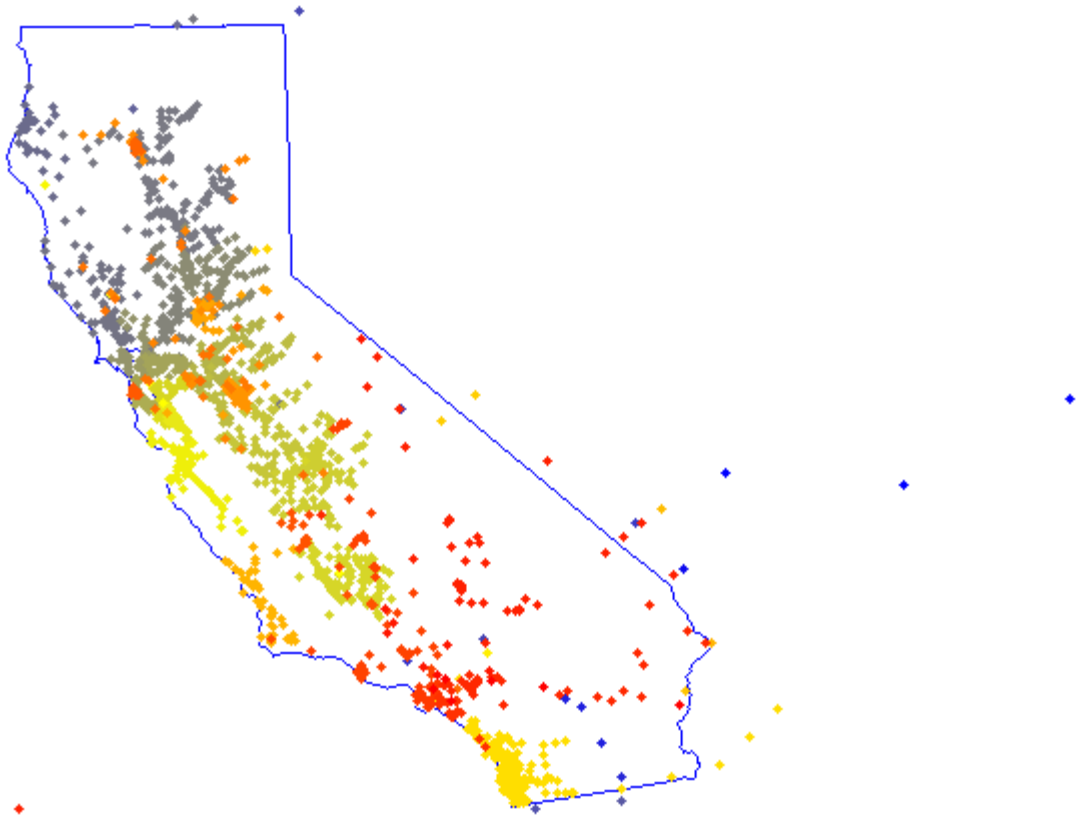
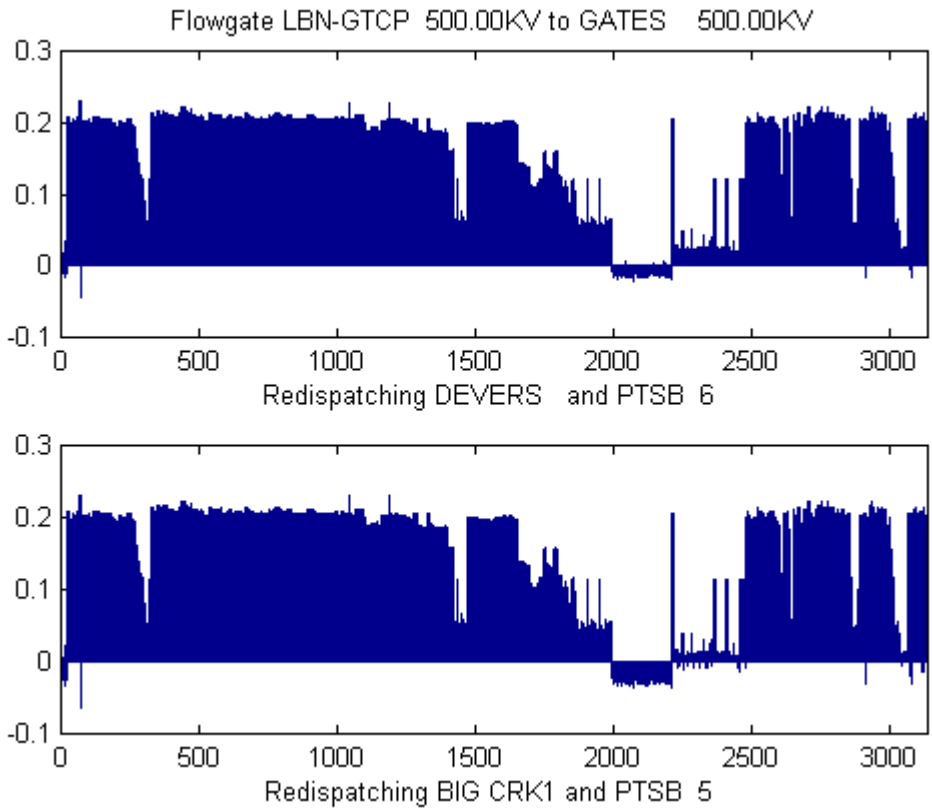
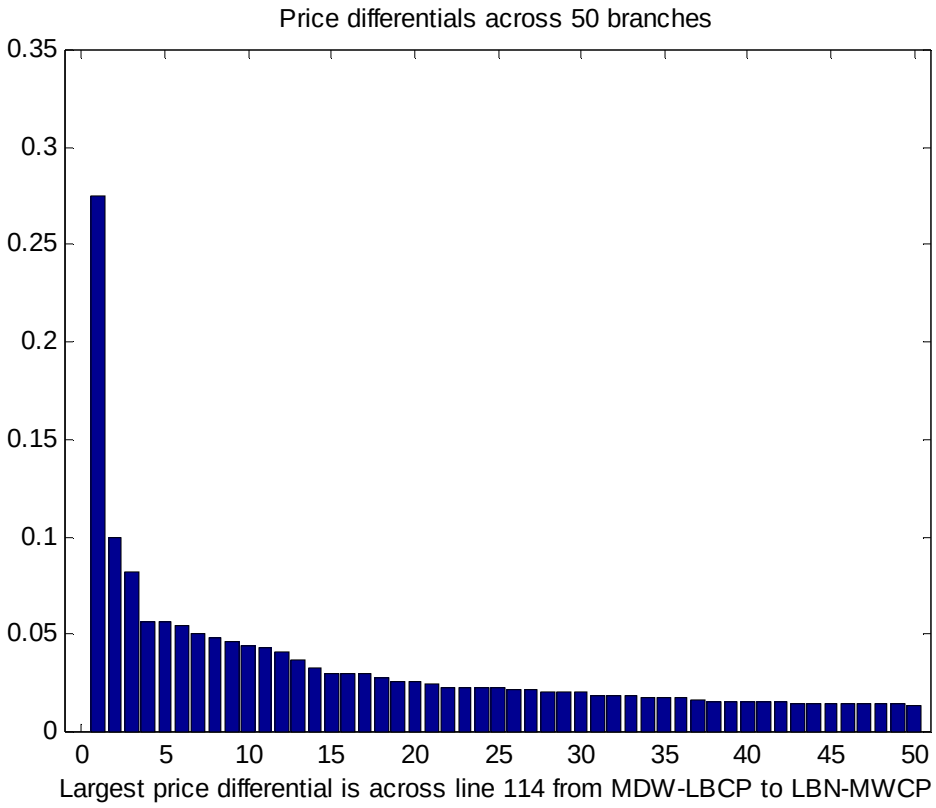


Figure 2: Zonal structure for present California system. Zones are color-coded.

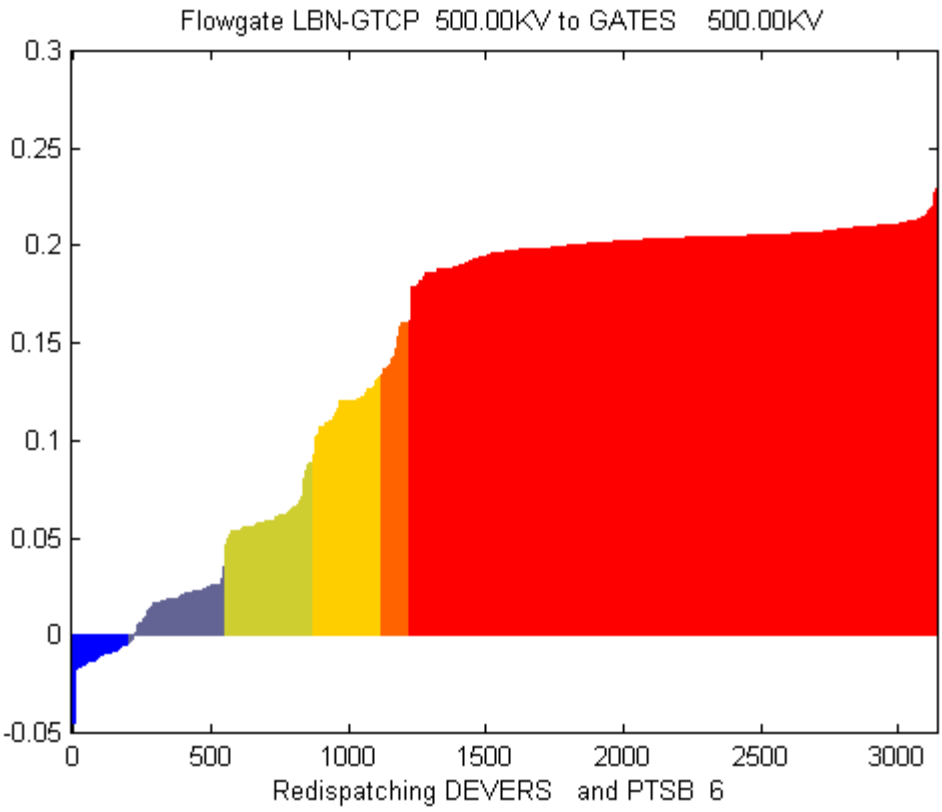
Path 15 congestion, flowgate is LBN-GCTP to GATES



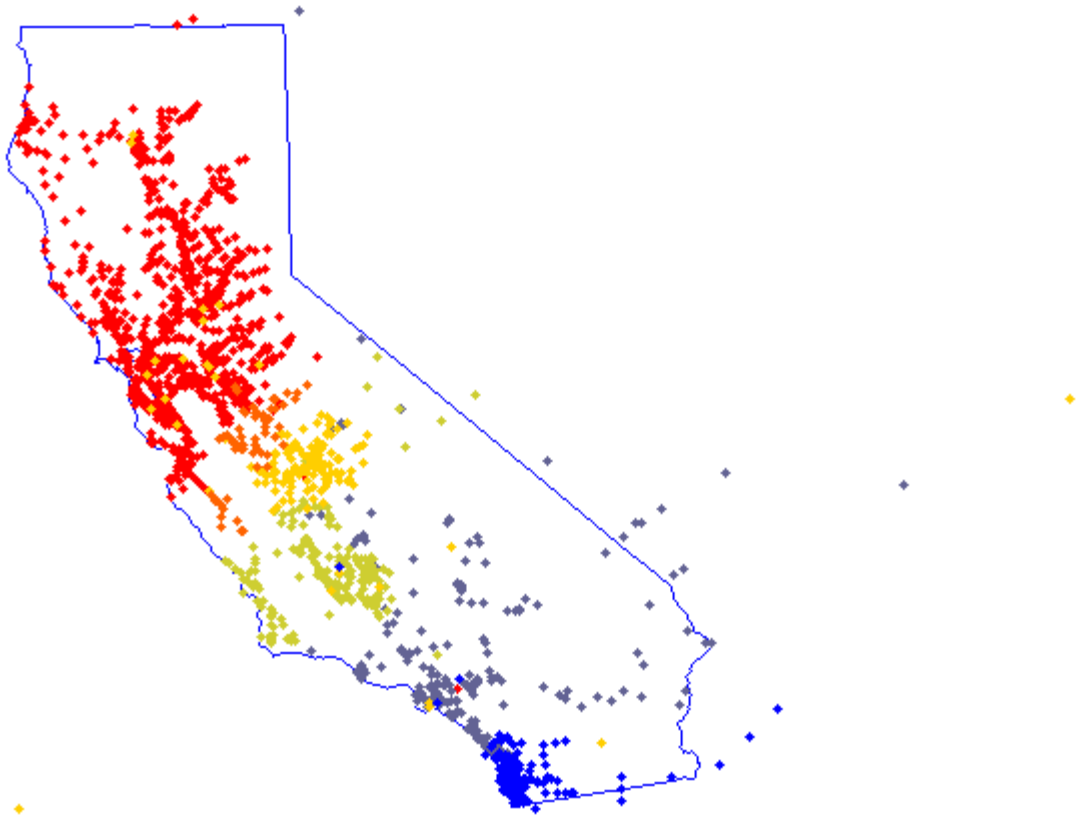
Nodal prices. Although using different generator pairs, both curves have essentially the same shape except for different vertical scaling, and a vertical offset.



Price differential across 50 most significant transmission lines and transformers as a result of nodal pricing.

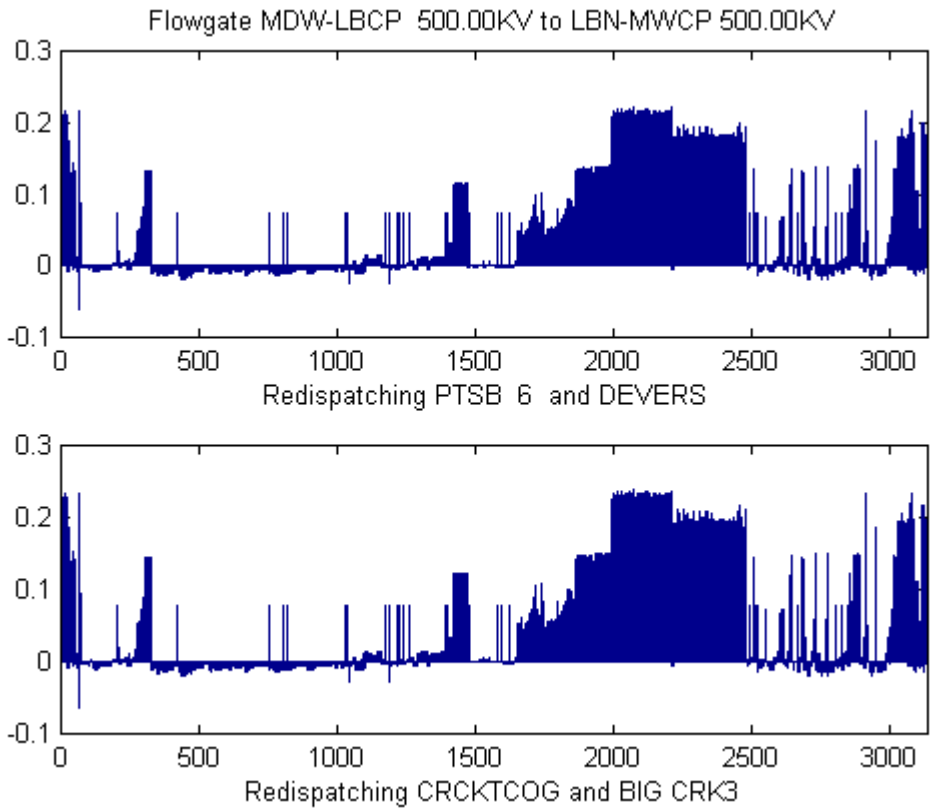


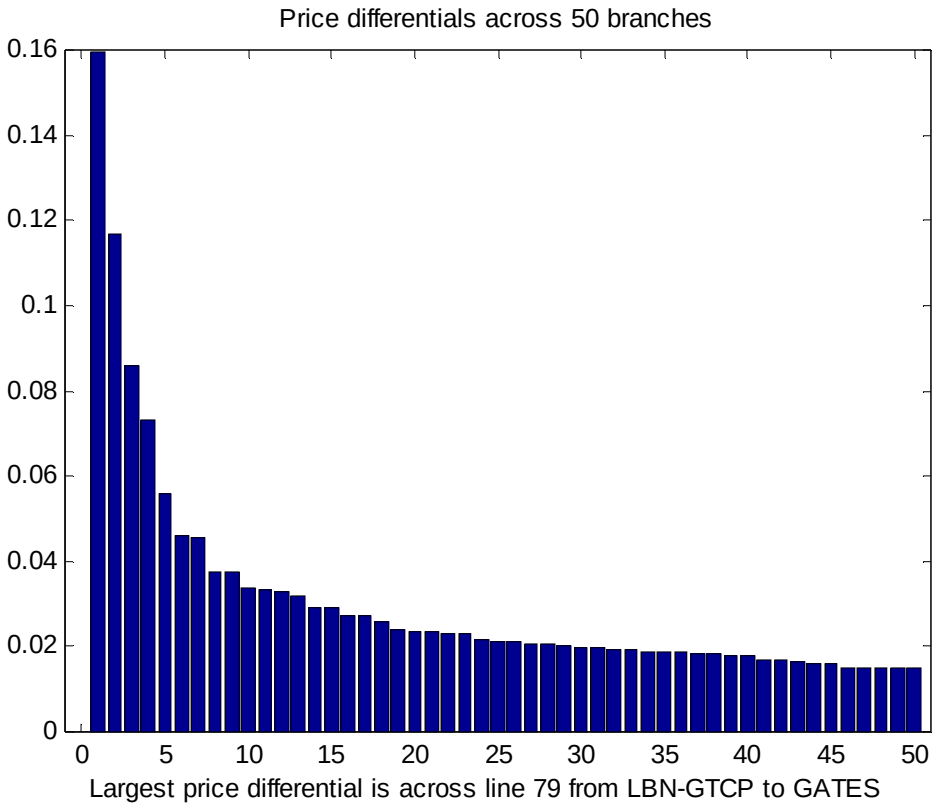
Sorted nodal prices organized into zones.

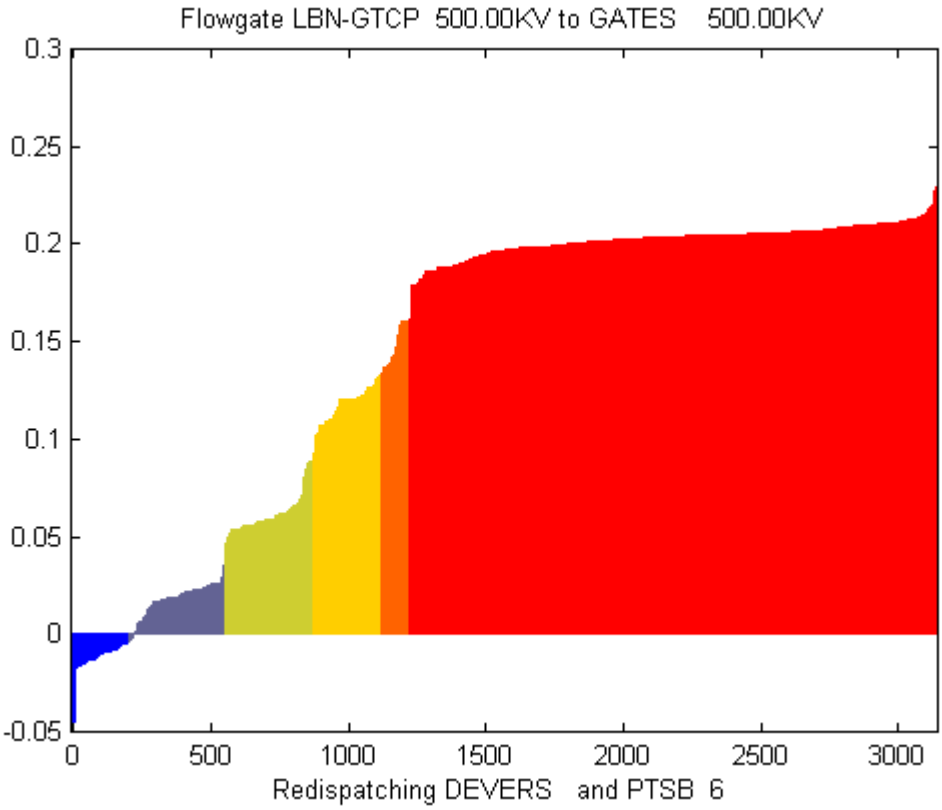


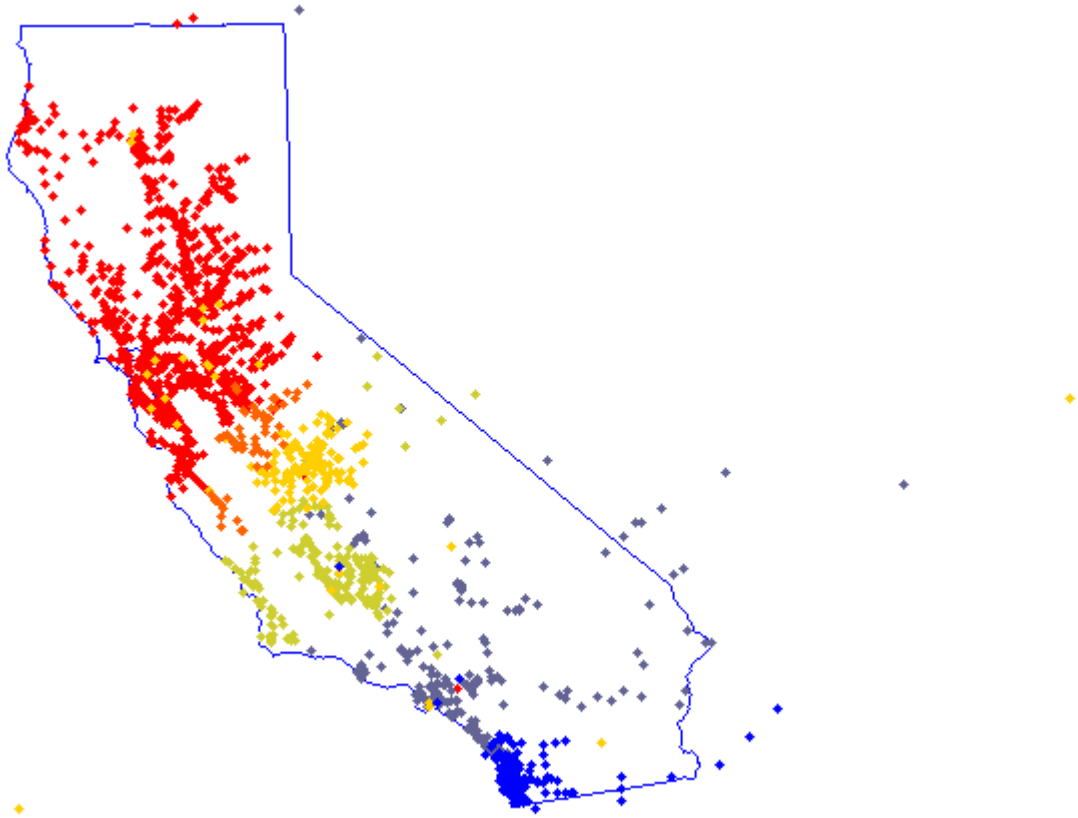
Zonal structure that results from congestion. The system has been organized into 6 zones.

Path 15 congestion, MDW-LBCP to LBN-MWCP flow constrained

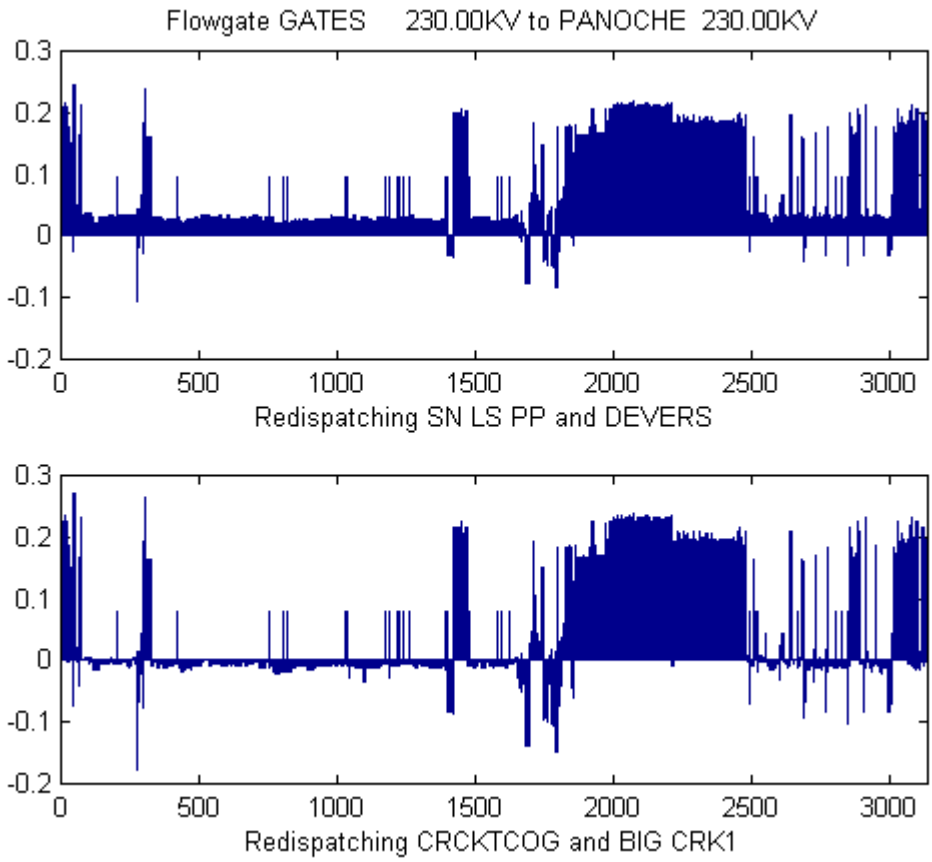


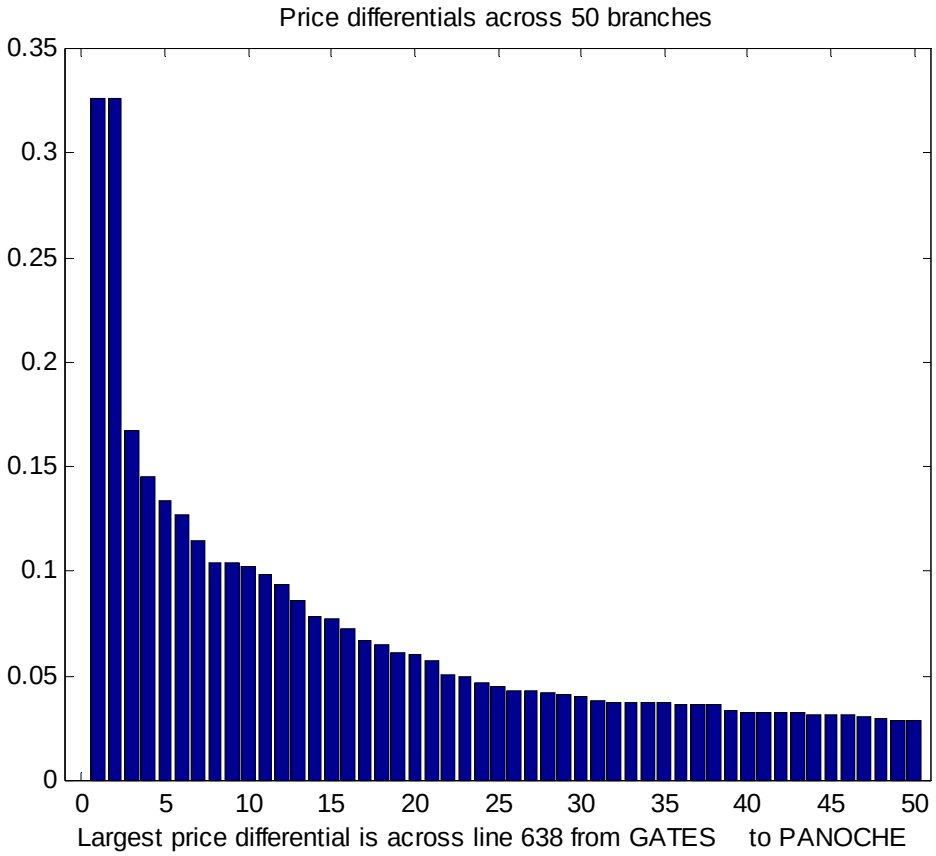

Price differentials across 50 branches
0.16
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 79 from LBN-GTCP to GATES

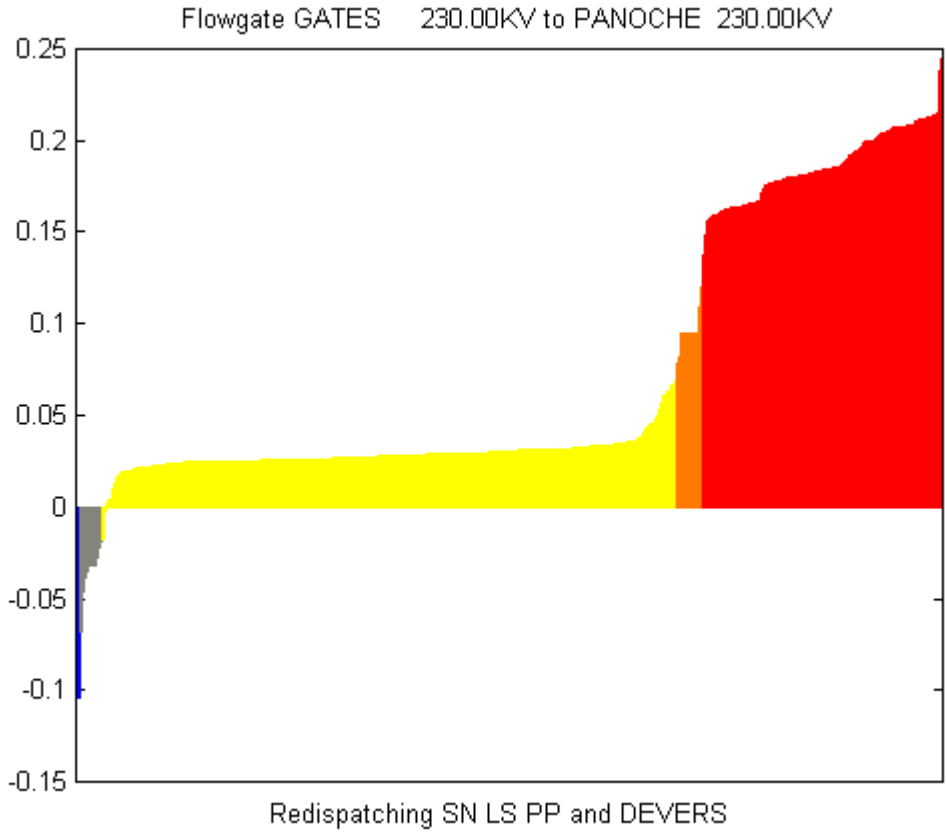

Flowgate LBN-GTCP 500.00KV to GATES 500.00KV
0.3
0.25
0.2
0.15
0.1
0.05
0
-0.05
0
500
1000
1500
2000
2500
3000
Redispatching DEVERS and PTSB 6

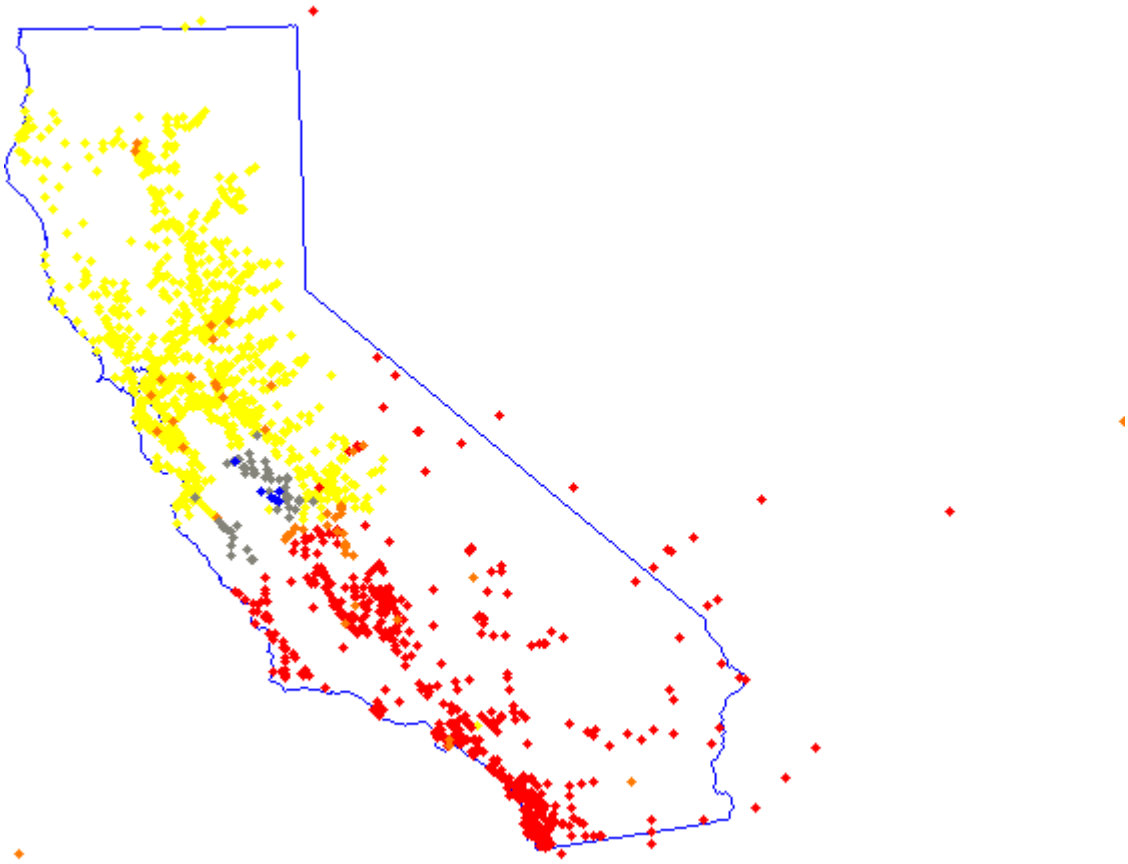


Path 15 congestion, GATES to PANOCHE possible flow constraint

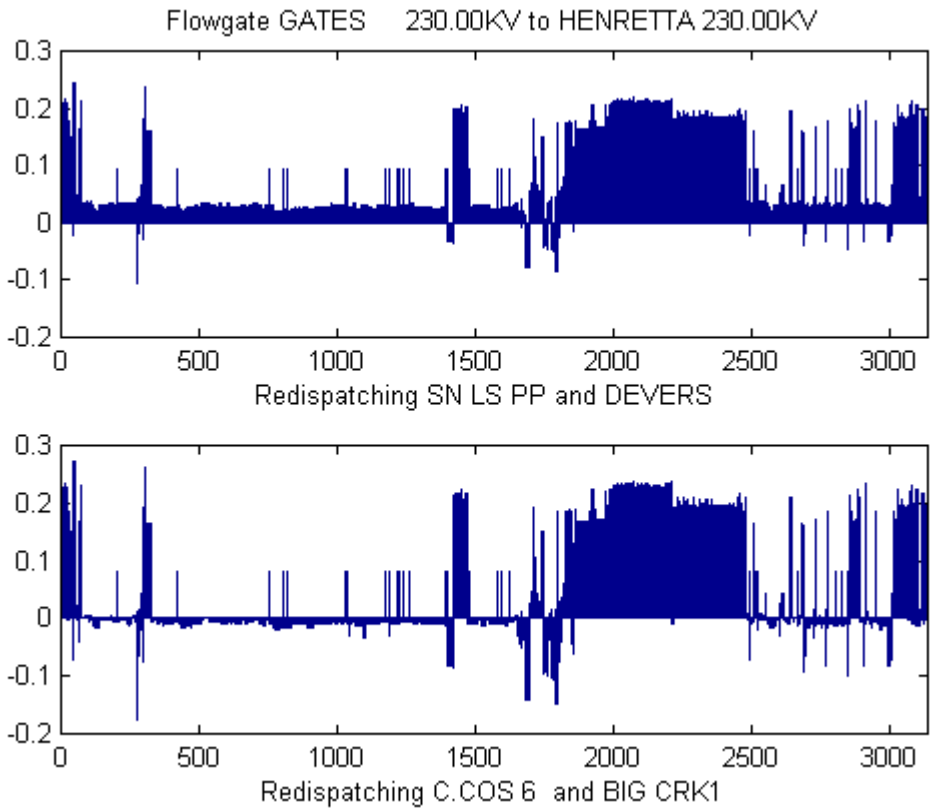


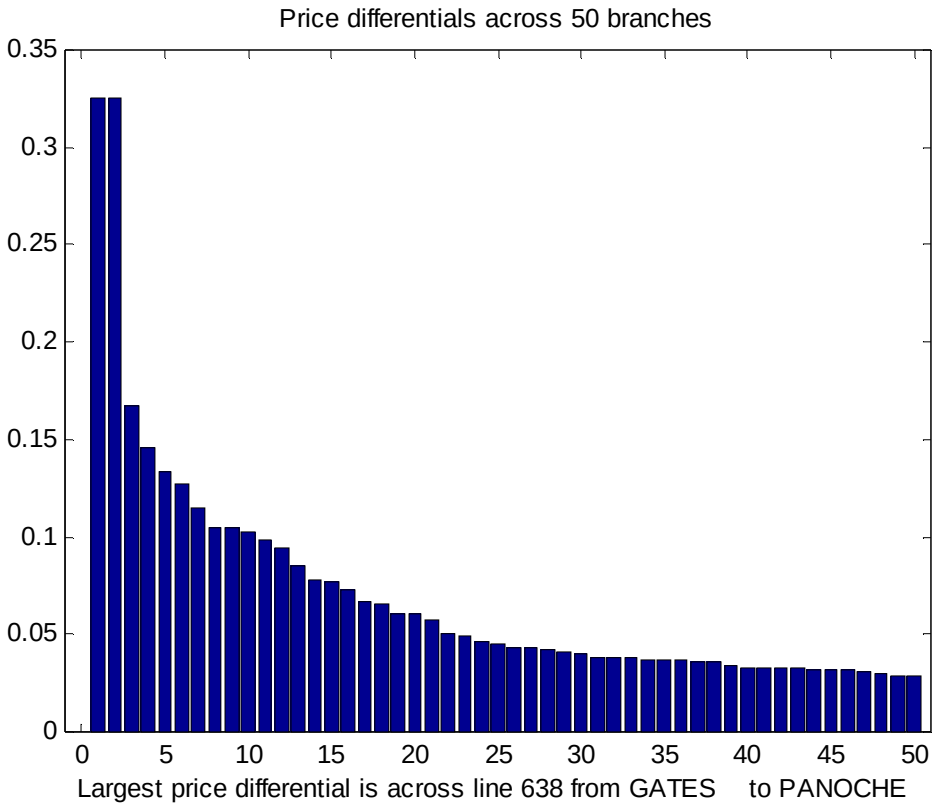

Price differentials across 50 branches
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 638 from GATES to PANOCHE

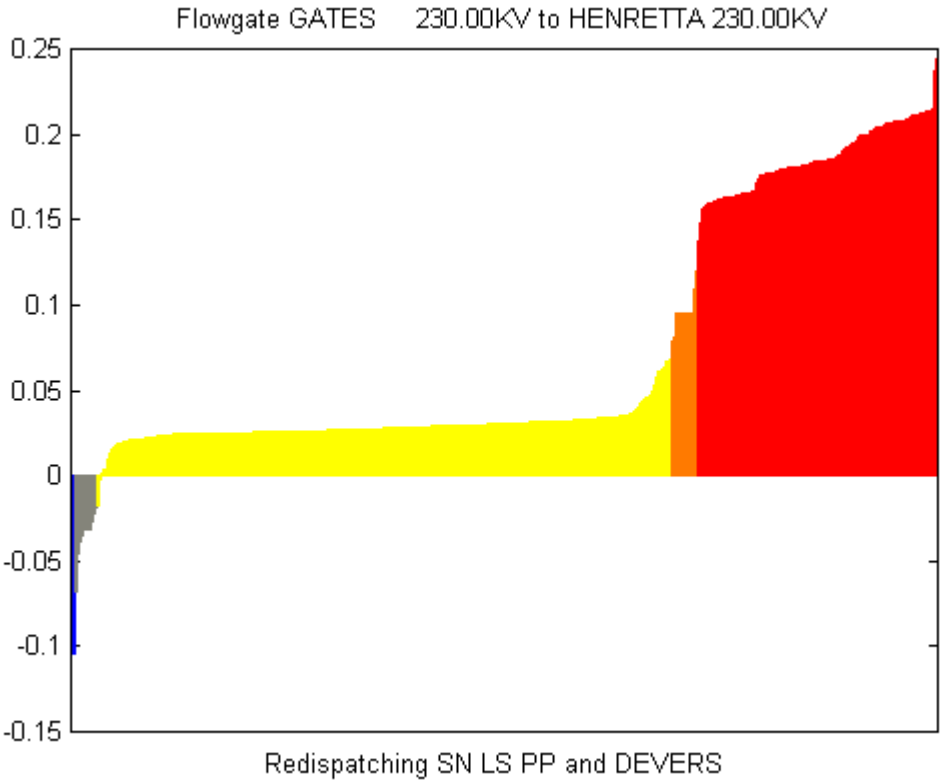

Flowgate GATES 230.00KV to PANOCHE 230.00KV
0.25
0.2
0.15
0.1
0.05
0
-0.05
-0.1
-0.15
Redispatching SN LS PP and DEVERS

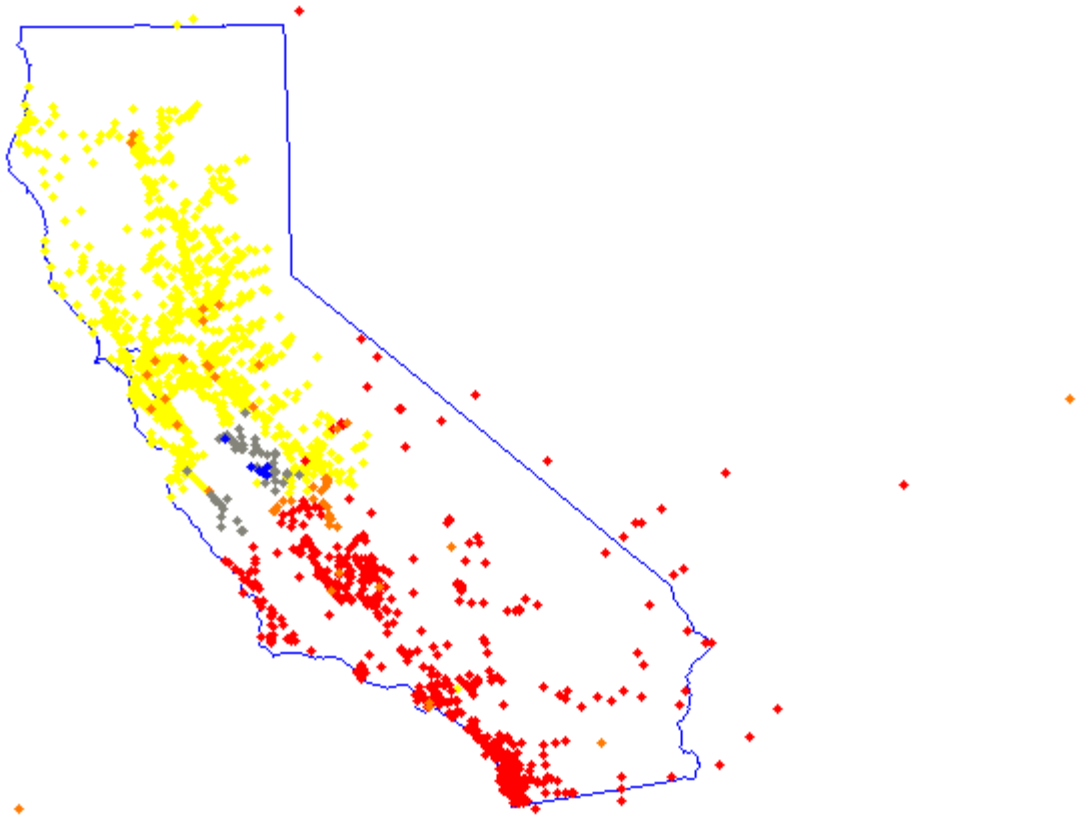


Path 15 congestion, GATES to HENRETTA possible flow constraint

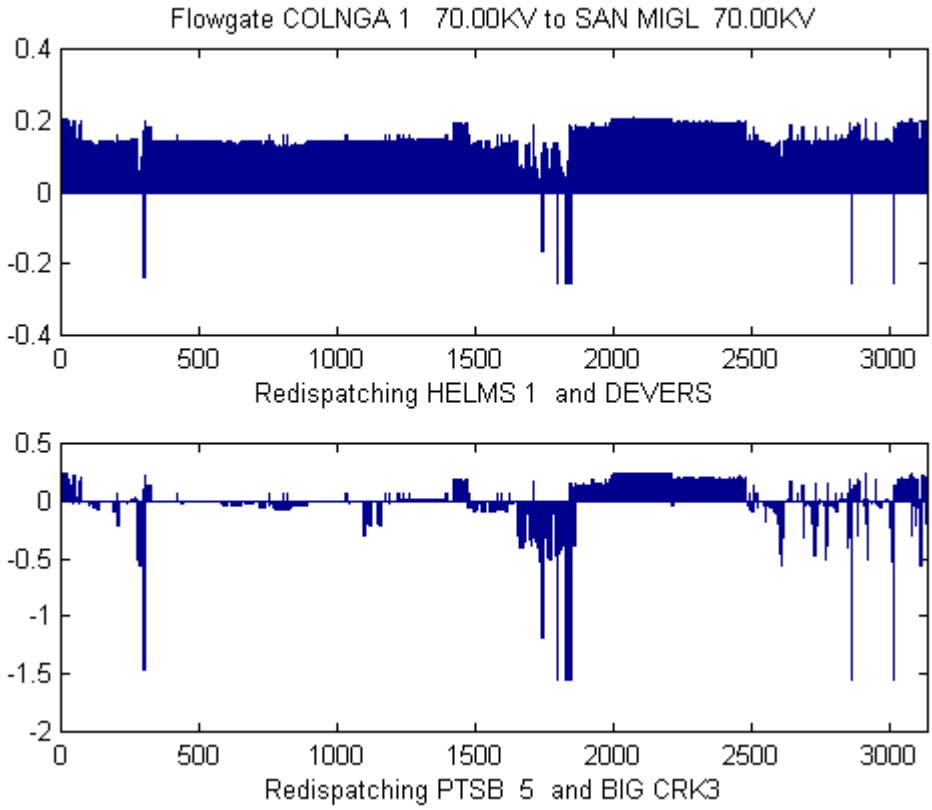


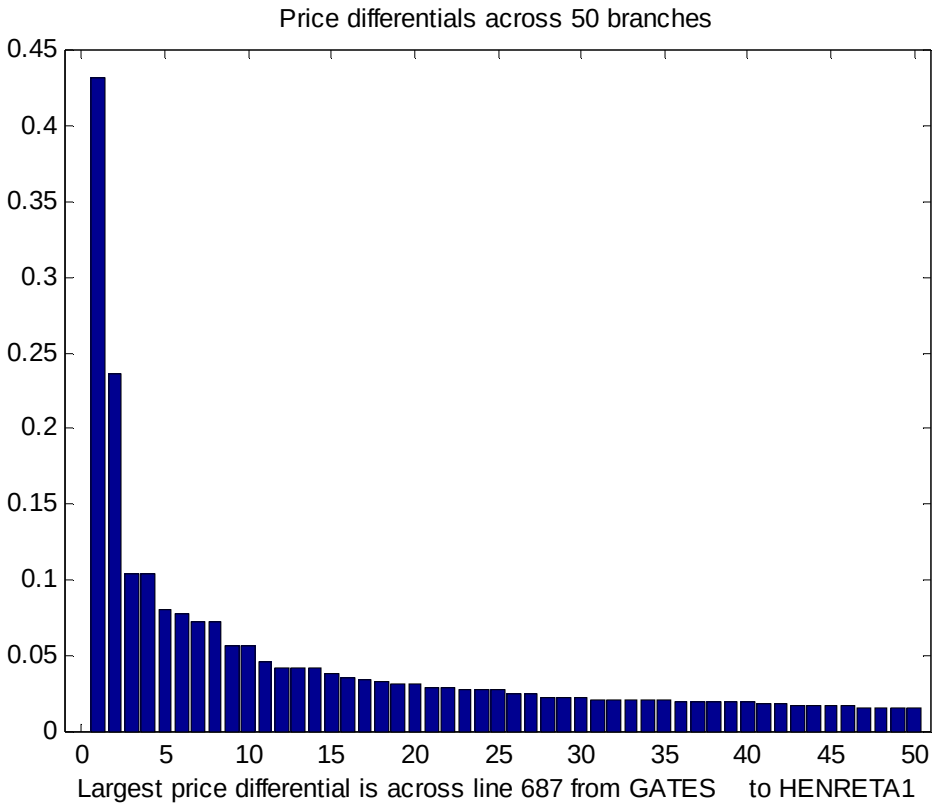

Price differentials across 50 branches
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 638 from GATES to PANOCHE

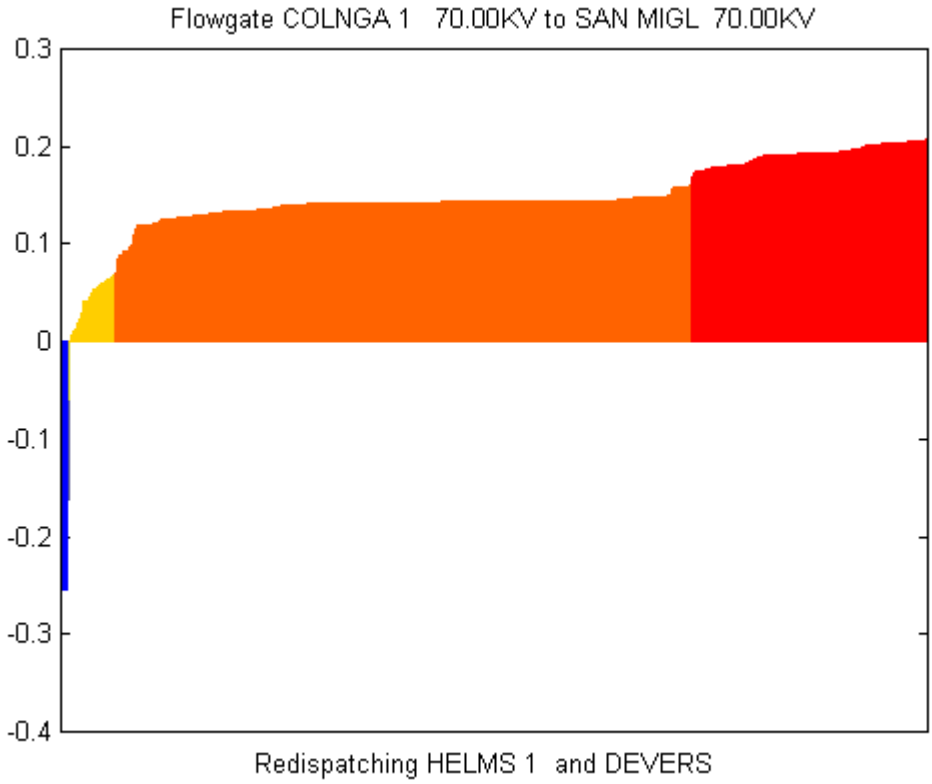

Flowgate GATES 230.00KV to HENRETTA 230.00KV
0.25
0.2
0.15
0.1
0.05
0
-0.05
-0.1
-0.15
Redispatching SN LS PP and DEVERS

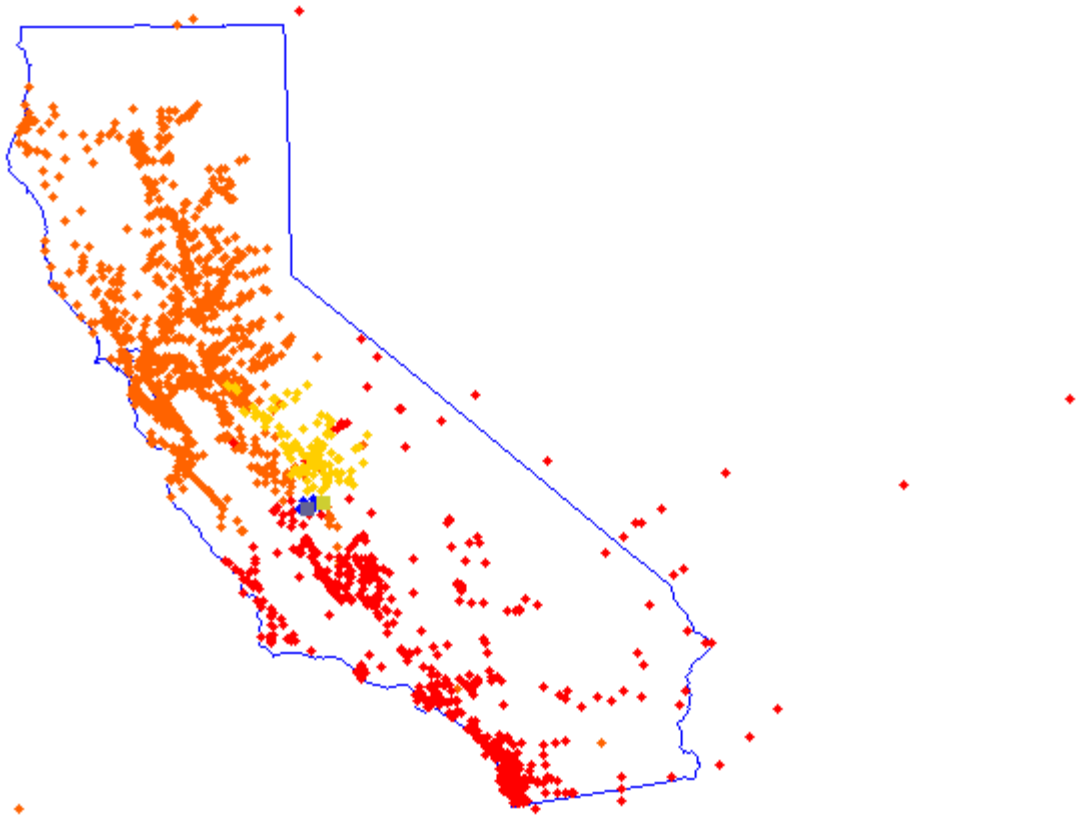


Path 15 congestion, COLNGA to SAN MIGL possible flow constraint

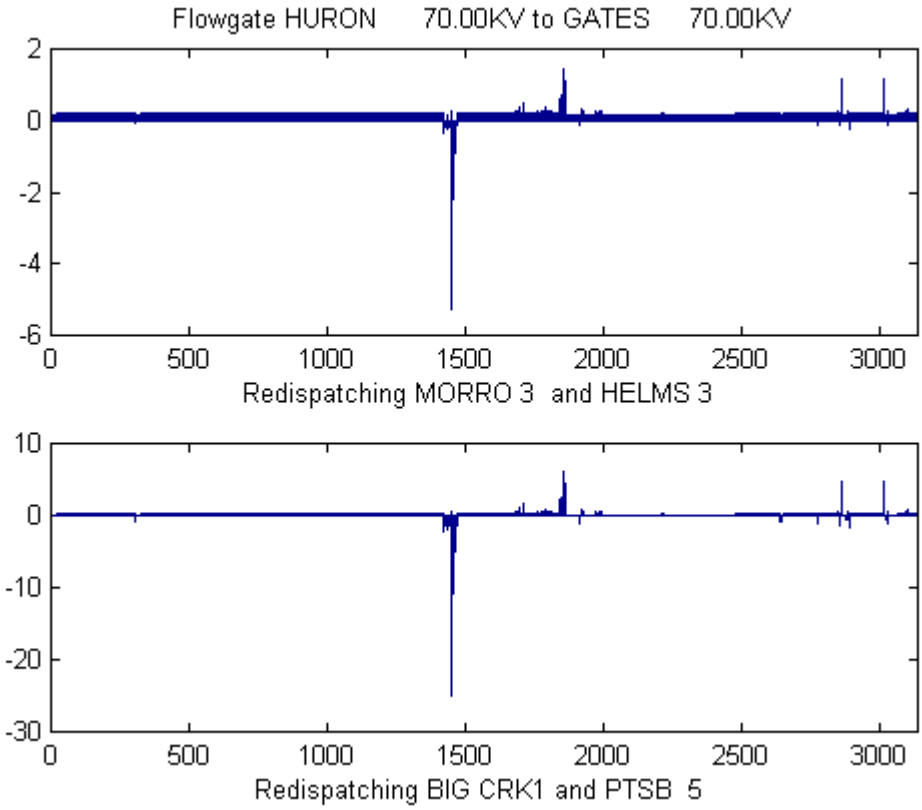


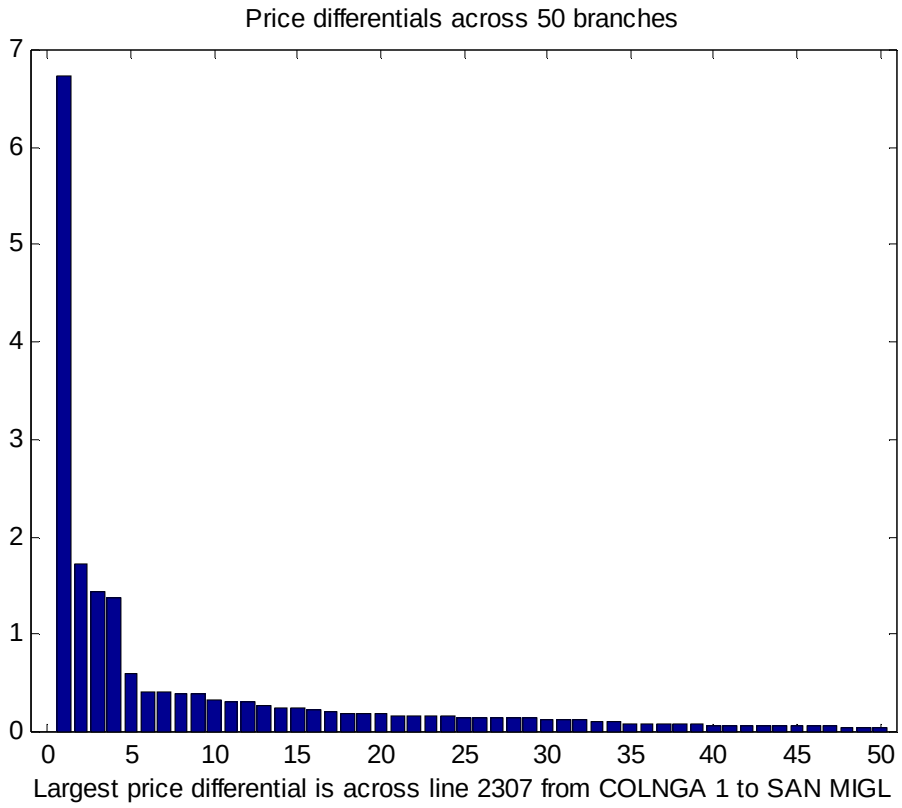

Price differentials across 50 branches
0.45
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 687 from GATES to HENRETA1

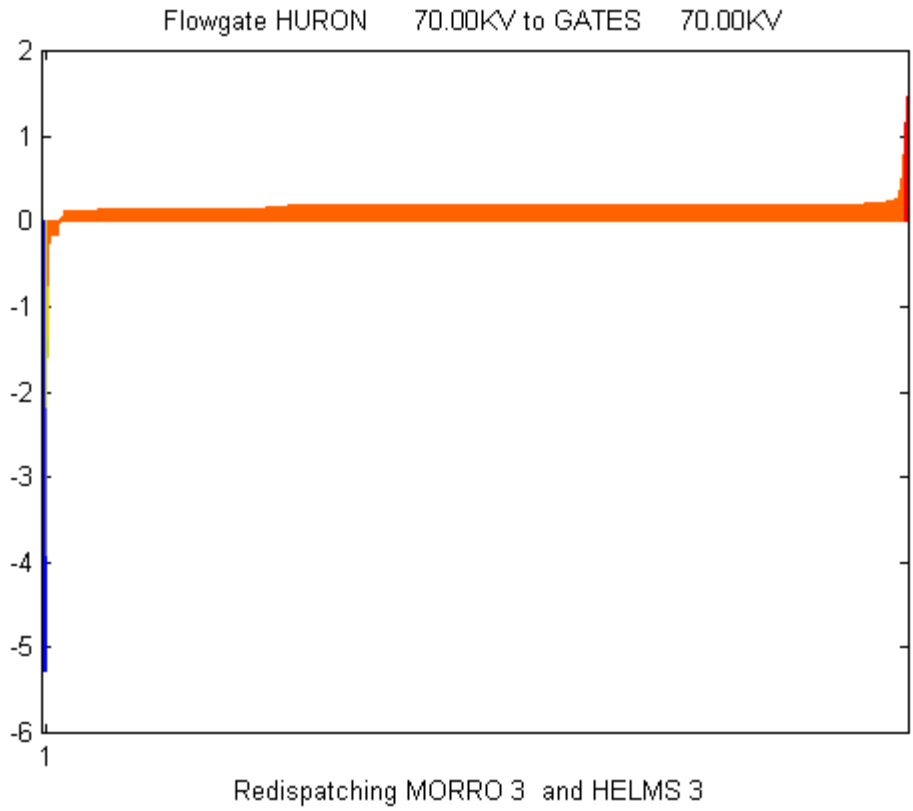

Flowgate COLNGA 1 70.00KV to SAN MIGL 70.00KV
0.3
0.2
0.1
0
-0.1
-0.2
-0.3
-0.4
Redispatching HELMS 1 and DEVERS

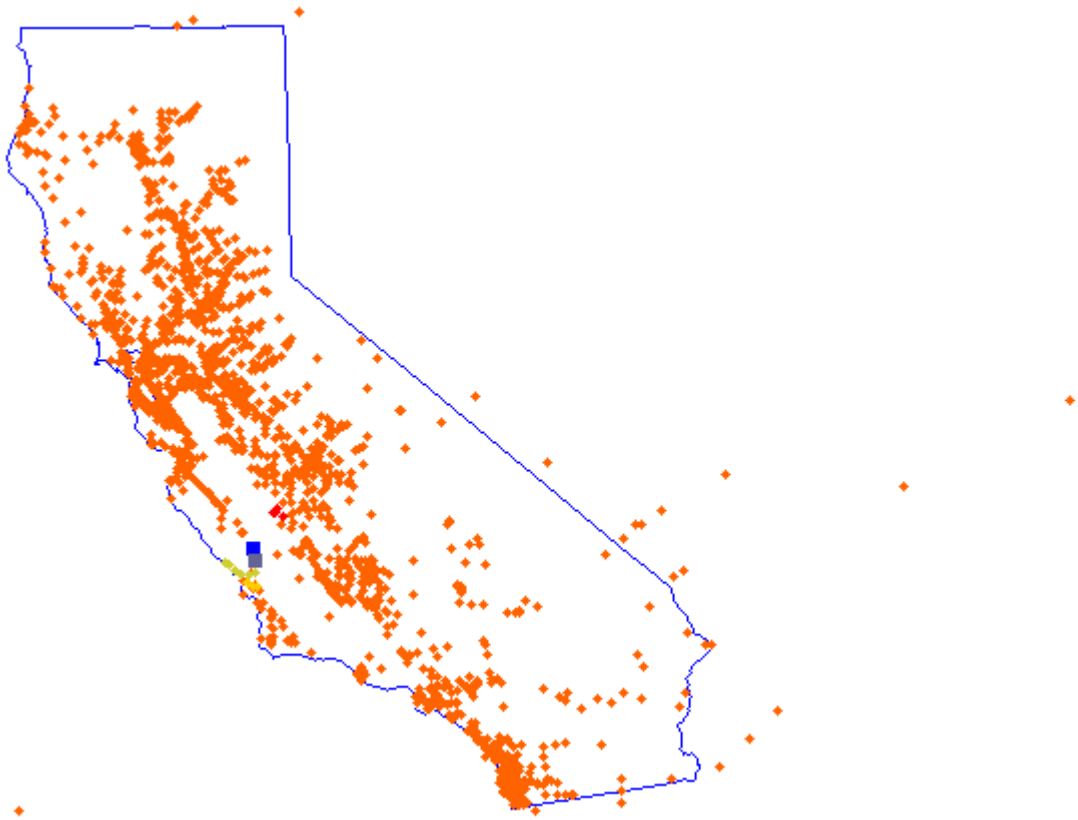


Path 15 congestion, HURON to GATES possible flow constraint

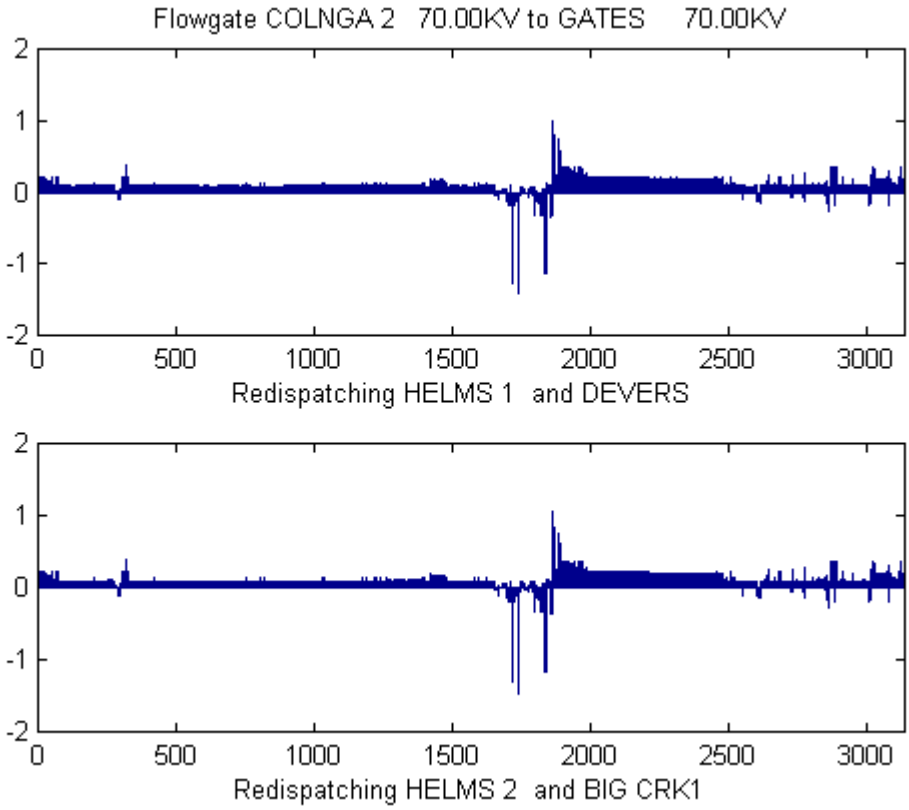


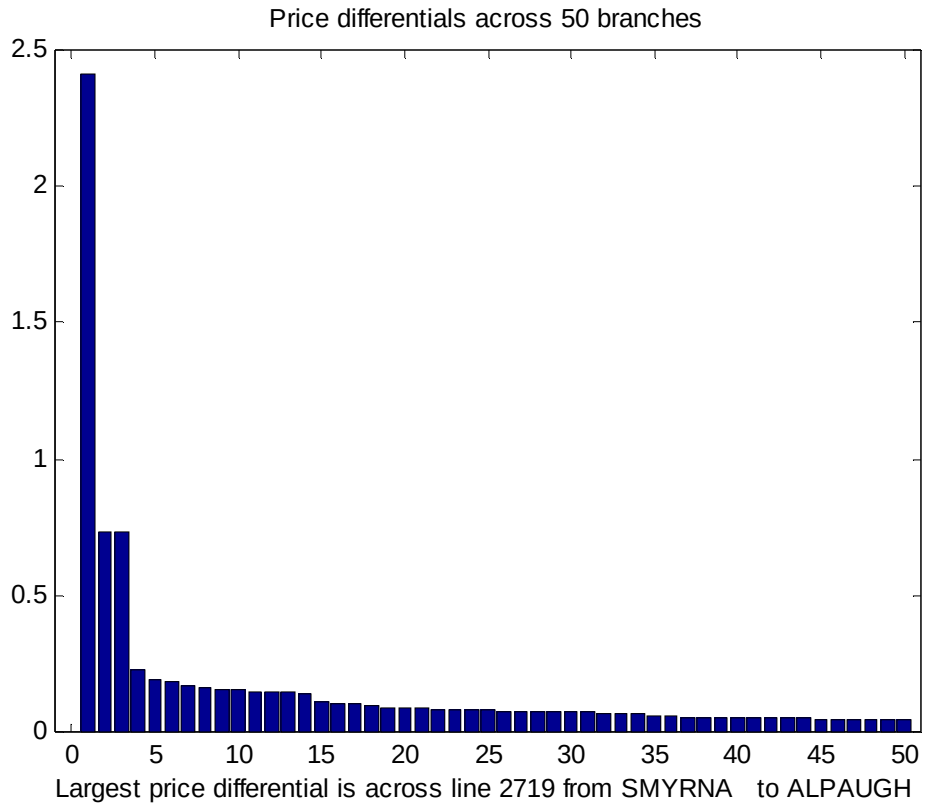

Price differentials across 50 branches
7
6
5
4
3
2
1
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 2307 from COLNGA 1 to SAN MIGL

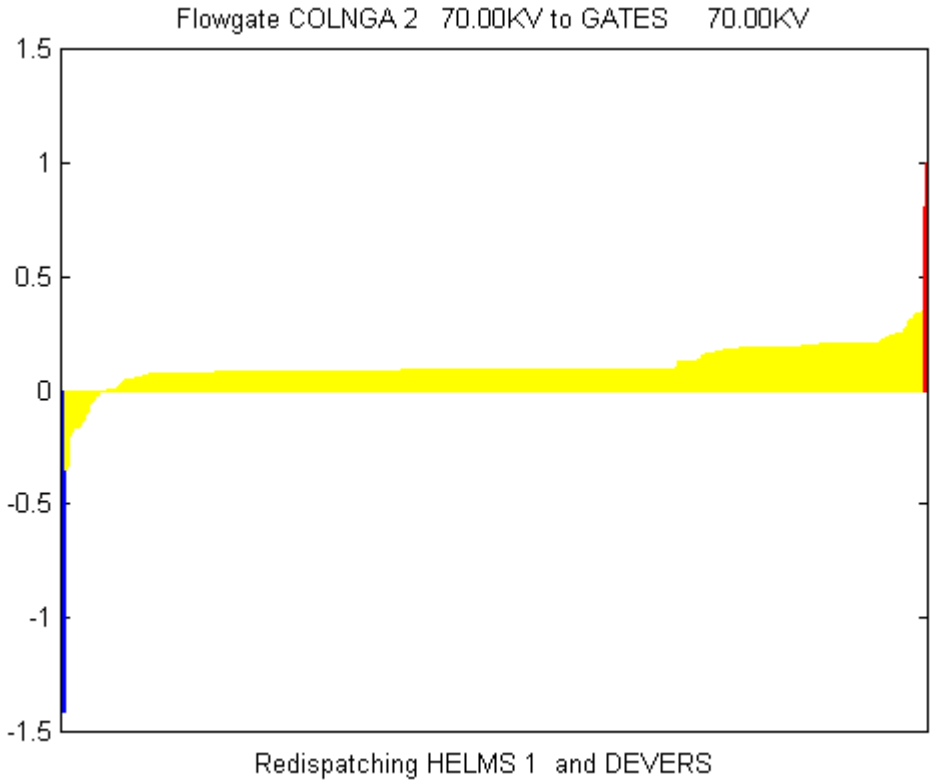

Flowgate HURON 70.00KV to GATES 70.00KV
2
1
0
-1
-2
-3
-4
-5
-6
1
Redispatching MORRO 3 and HELMS 3

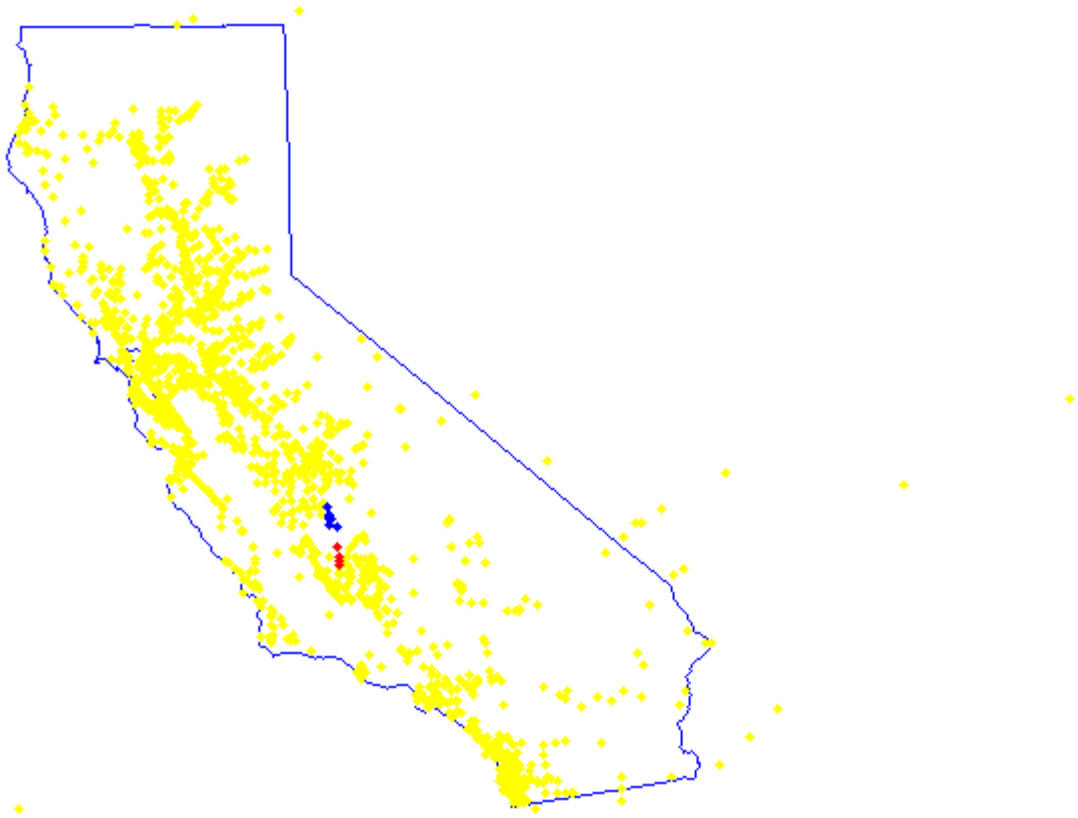


Path 15 congestion, COLNGA to GATES possible flow constraint

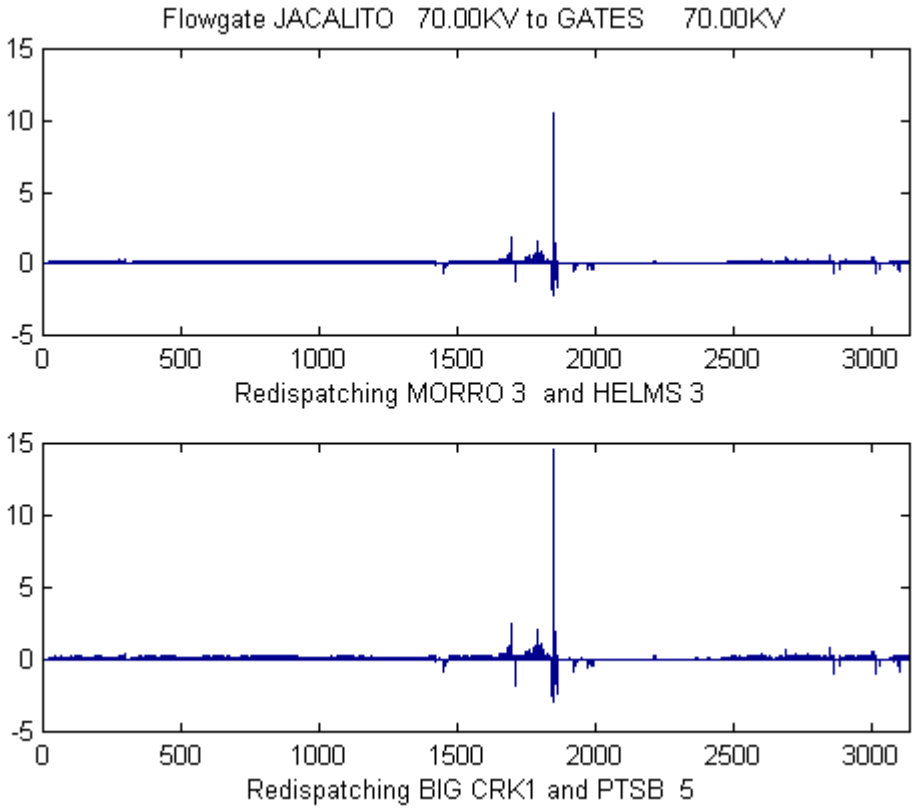


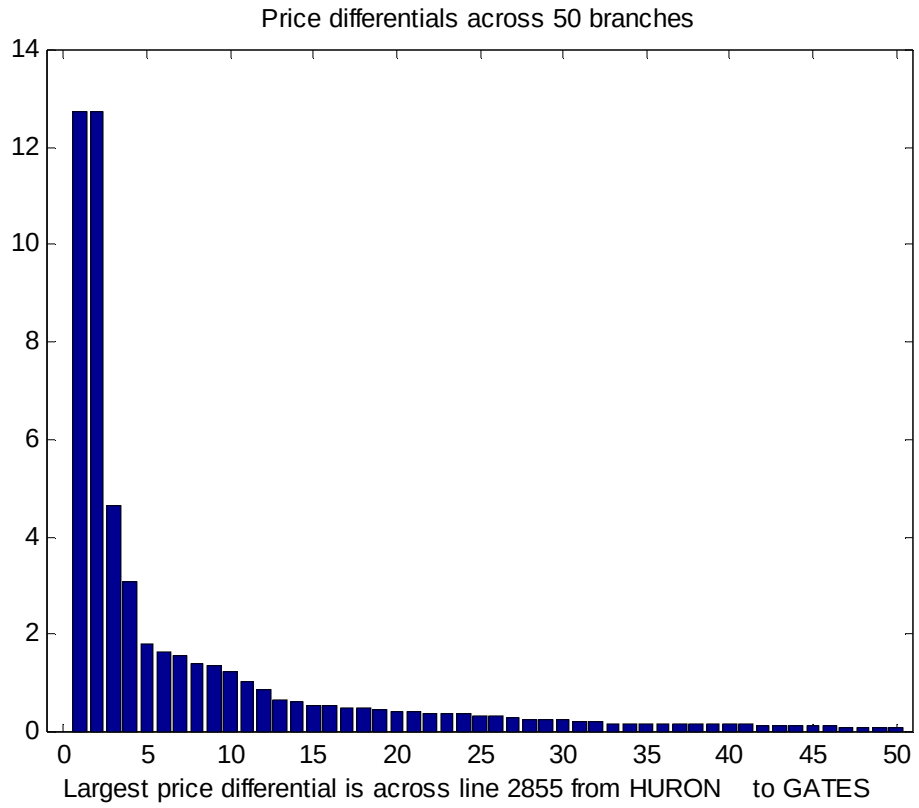

Price differentials across 50 branches
2.5
2
1.5
1
0.5
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 2719 from SMYRNA to ALPAUGH

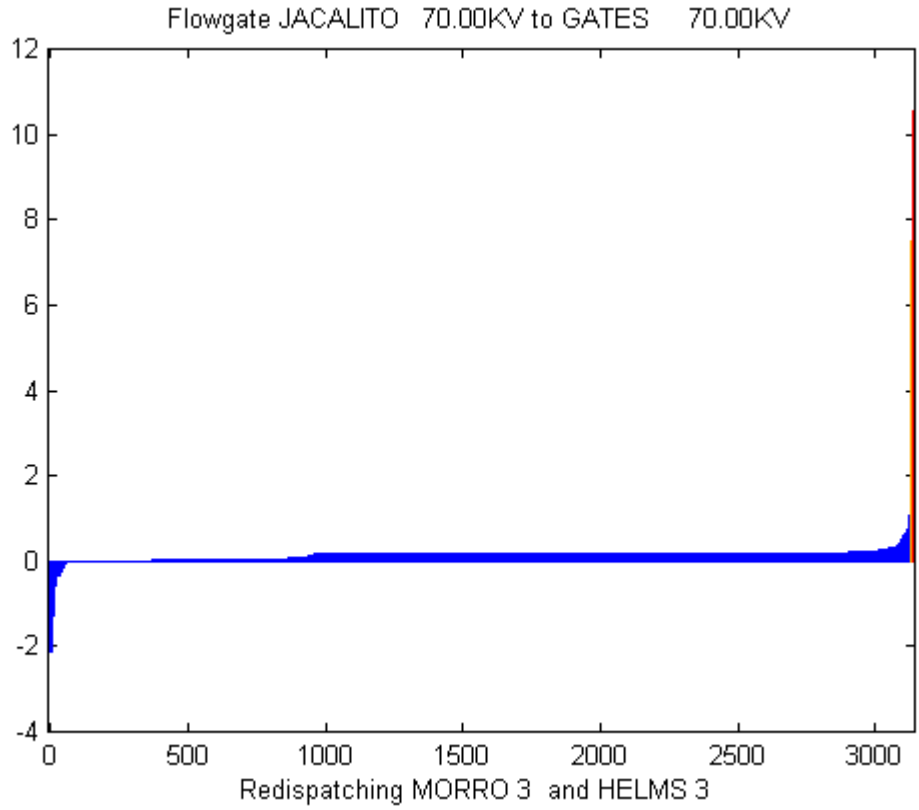

Flowgate COLNGA 2 70.00KV to GATES 70.00KV
1.5
1
0.5
0
-0.5
-1
-1.5
Redispatching HELMS 1 and DEVERS

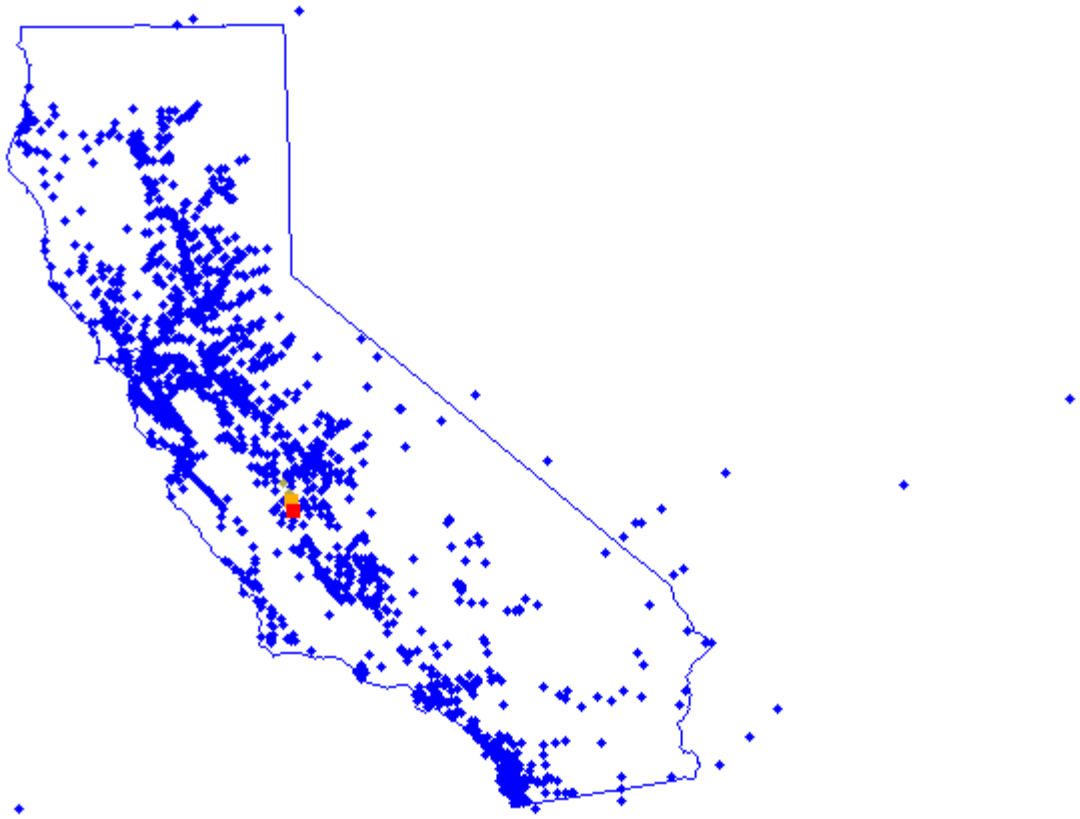


Path 15 congestion, JACALITO to GATES possible flow constraint

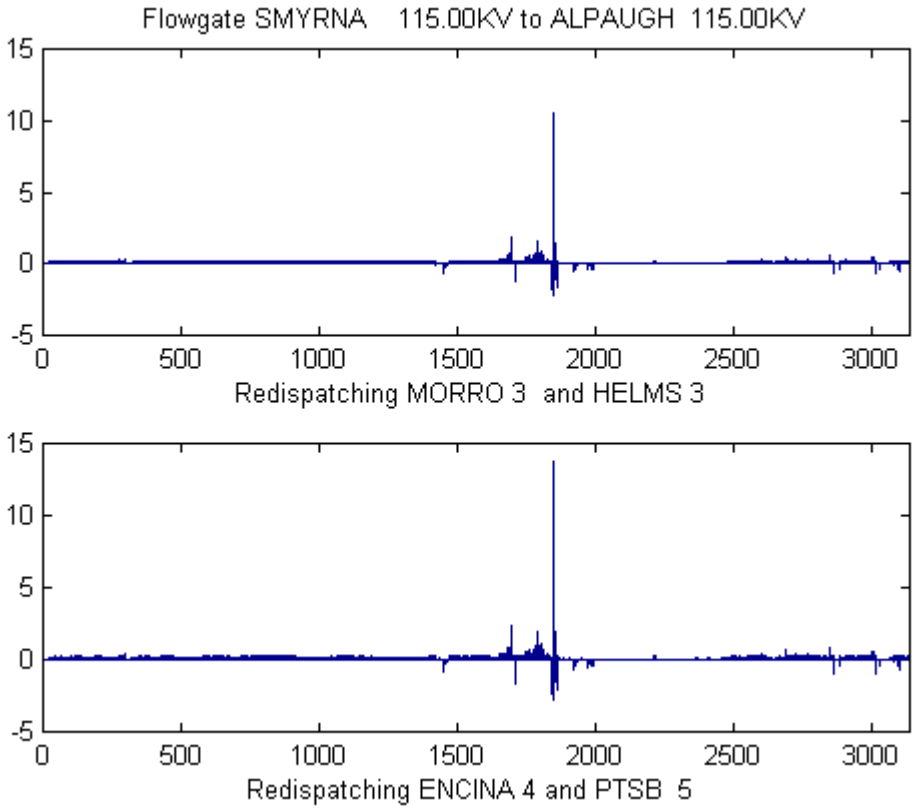


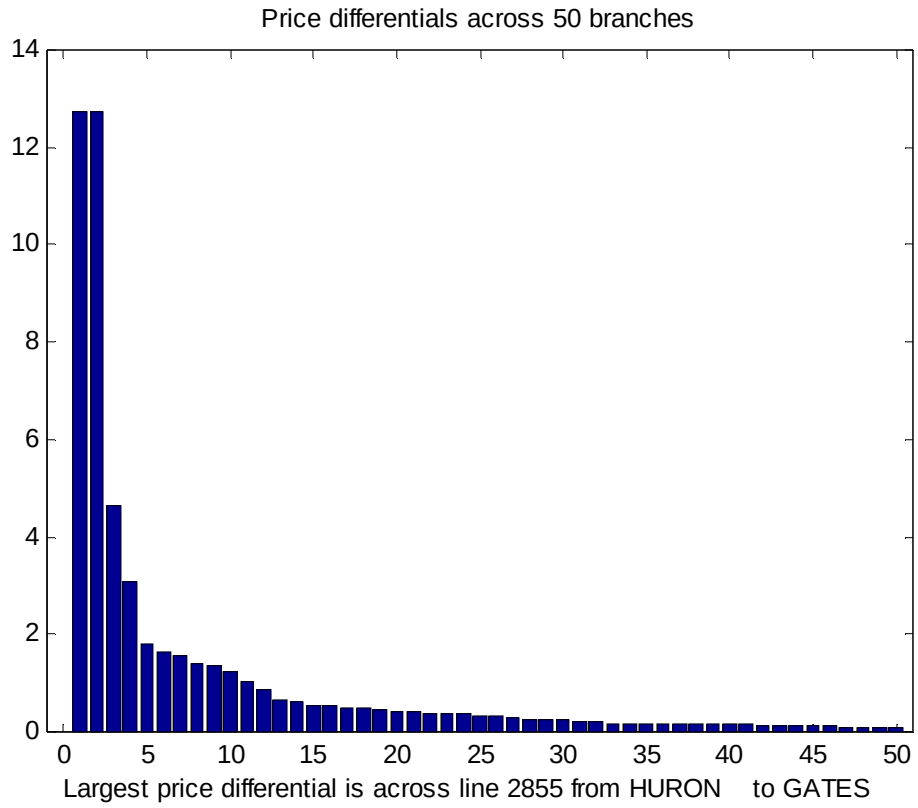

Price differentials across 50 branches
14
12
10
8
6
4
2
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 2855 from HURON to GATES

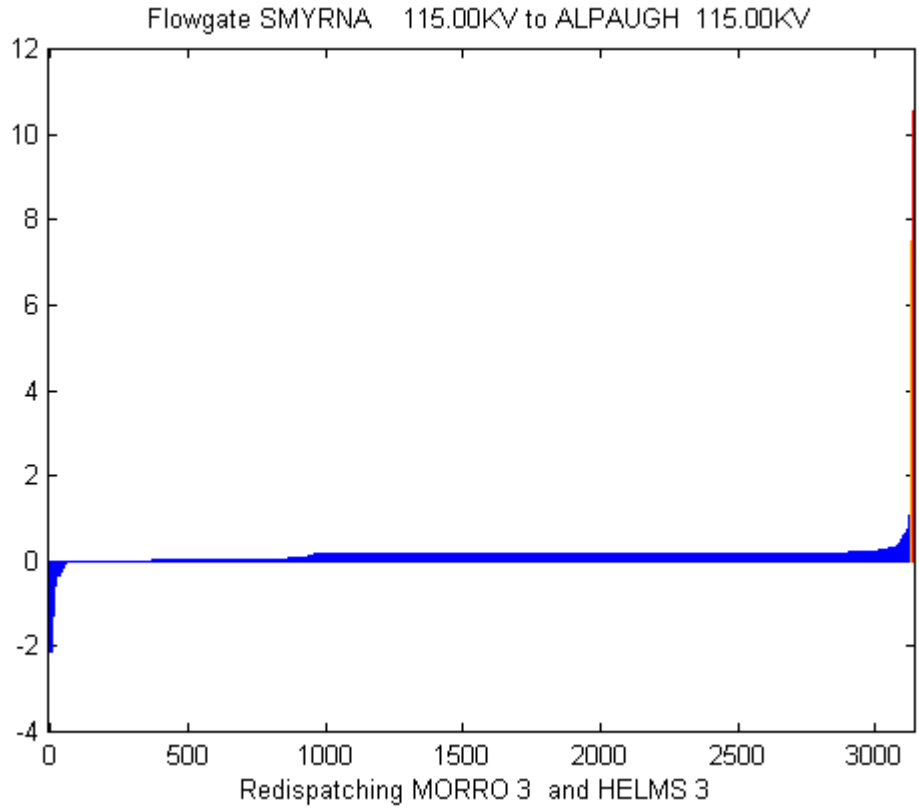

Flowgate JACALITO 70.00KV to GATES 70.00KV
12
10
8
6
4
2
0
-2
-4
0
500
1000
1500
2000
2500
3000
Redispatching MORRO 3 and HELMS 3

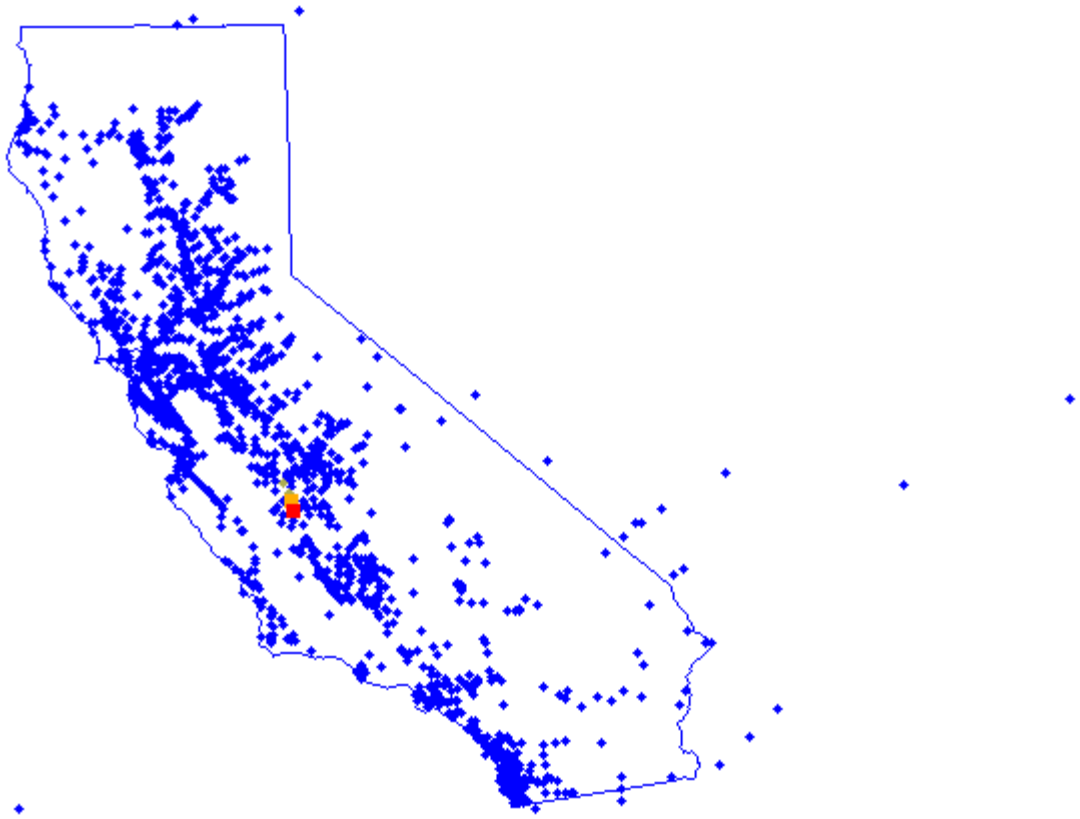


Path 15 congestion, SMYRNA to ALPAUGH possible flow constraint

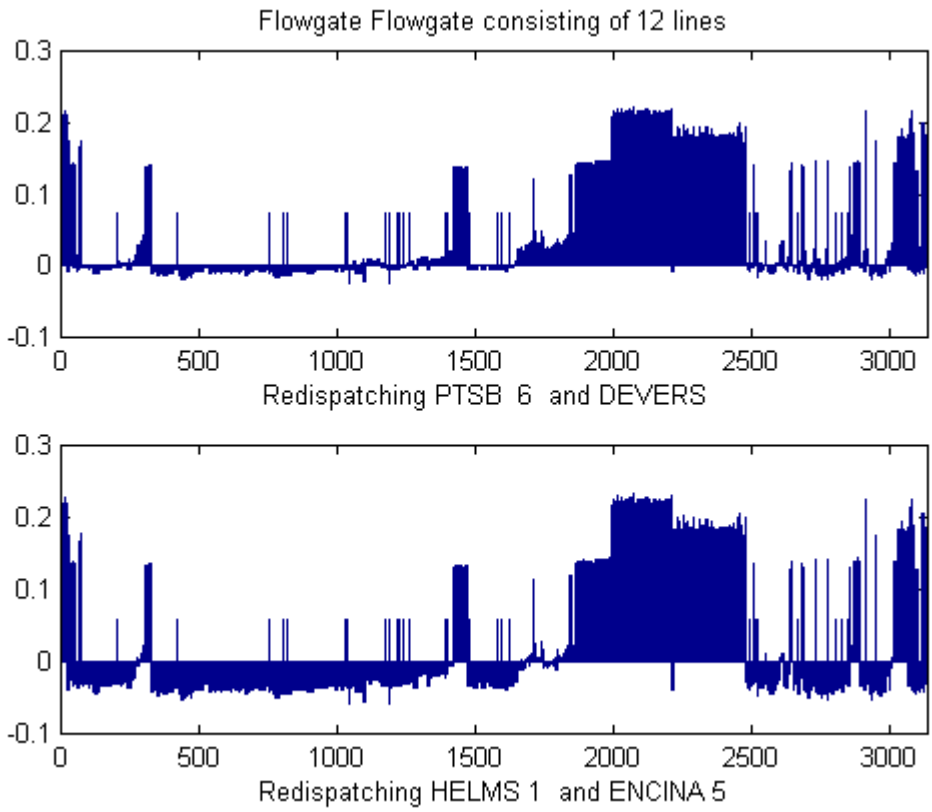


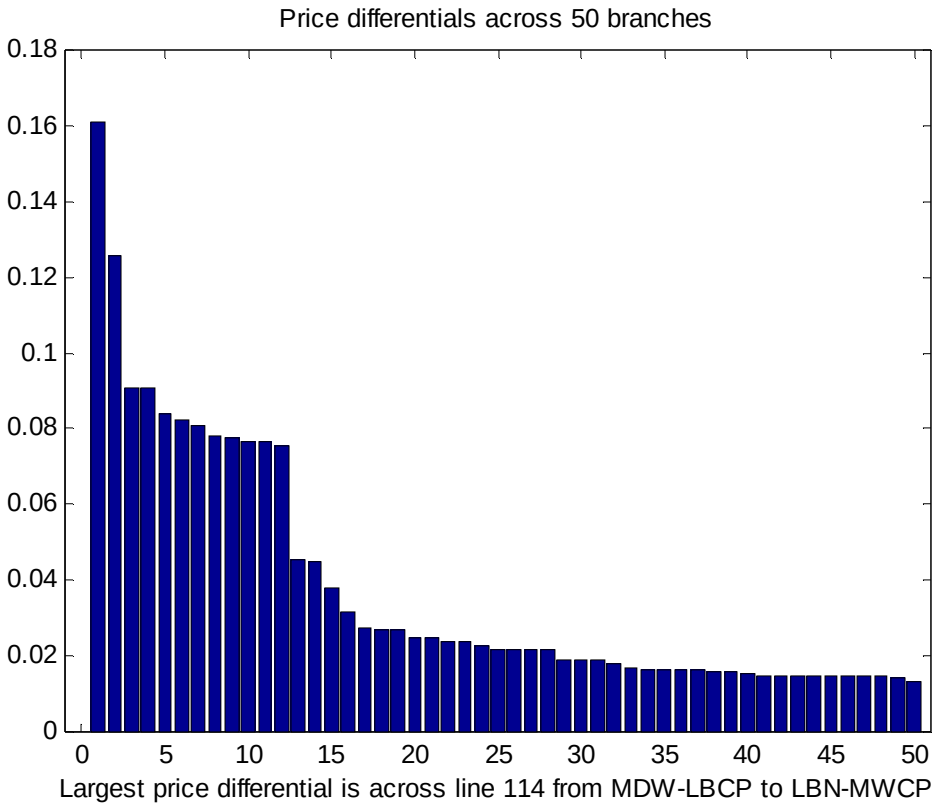

Price differentials across 50 branches
14
12
10
8
6
4
2
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 2855 from HURON to GATES

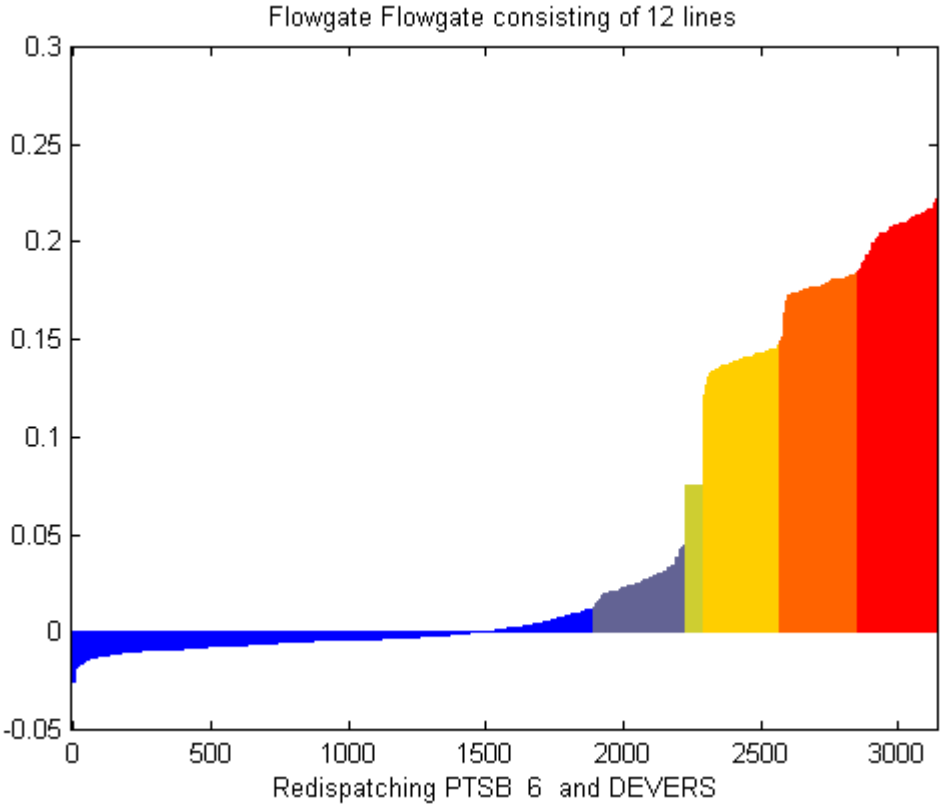

Flowgate SMYRNA 115.00KV to ALPAUGH 115.00KV
12
10
8
6
4
2
0
-2
-4
0
500
1000
1500
2000
2500
3000
Redispatching MORRO 3 and HELMS 3

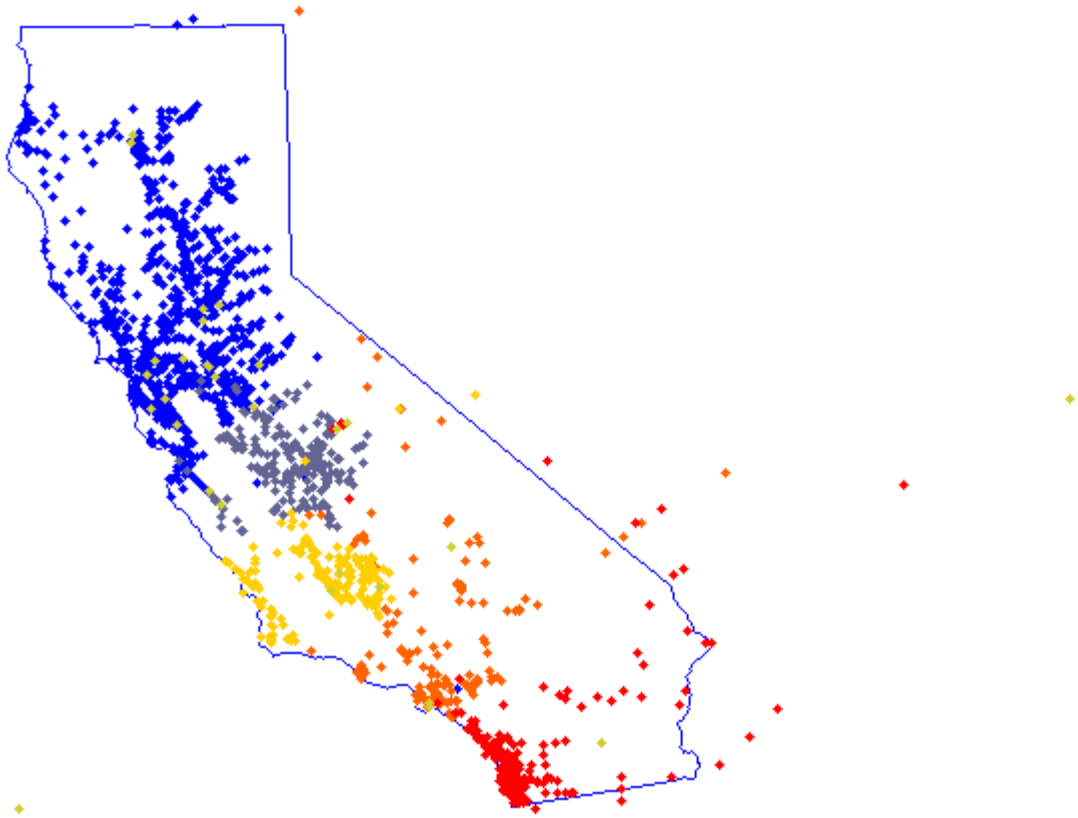


Path 15 congestion, flowgate is the sum of all powers across the interface

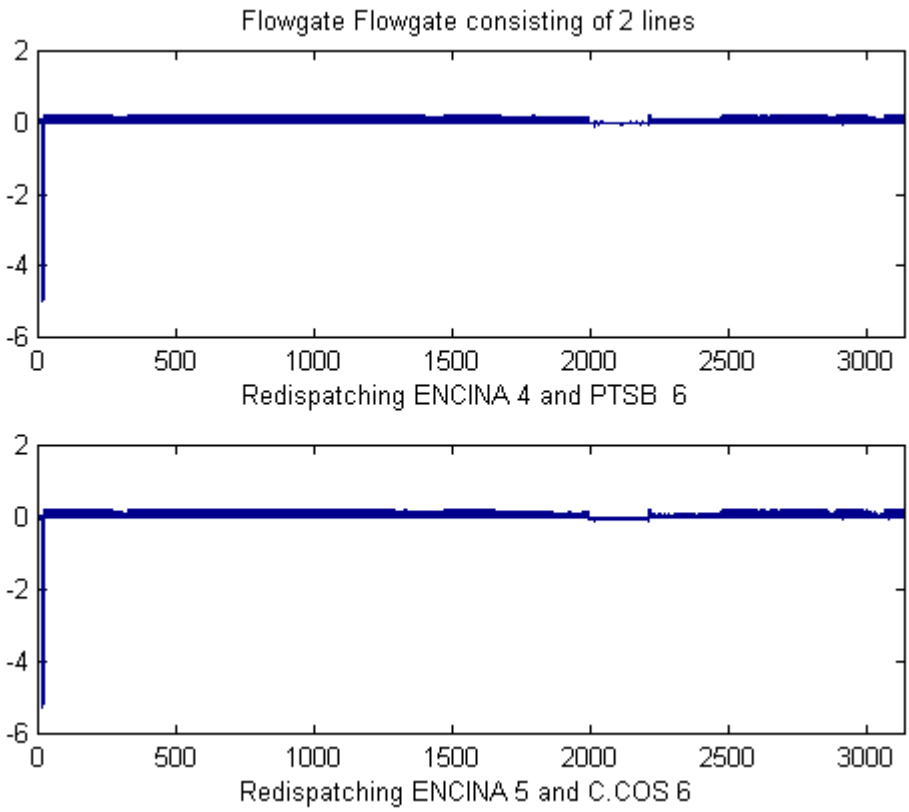


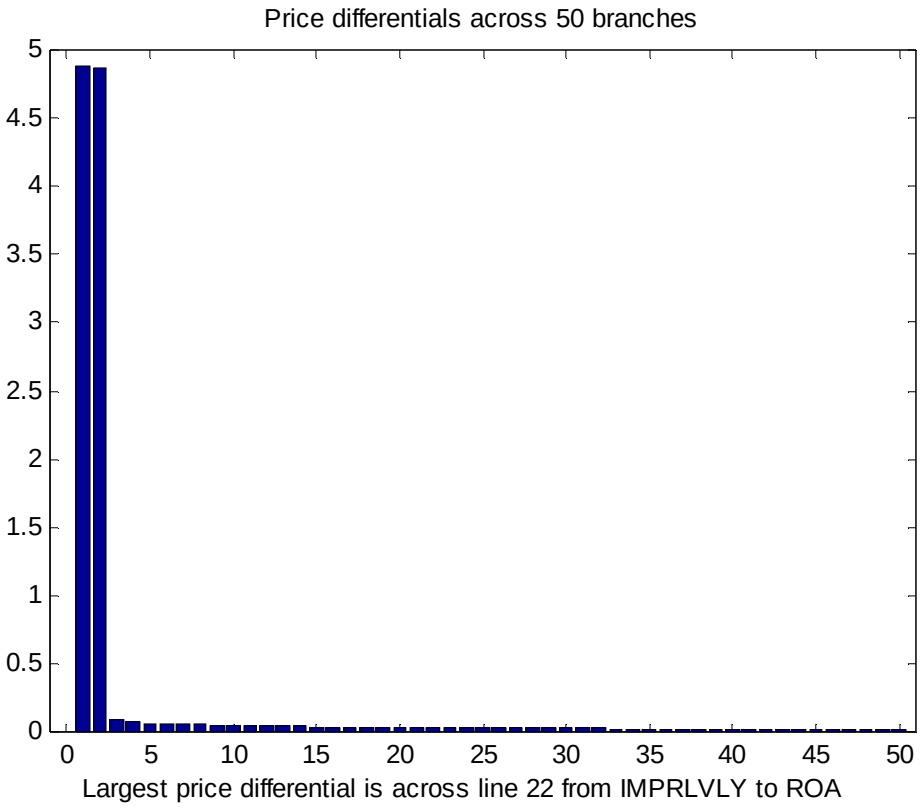

Price differentials across 50 branches
0.18
0.16
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 114 from MDW-LBCP to LBN-MWCP

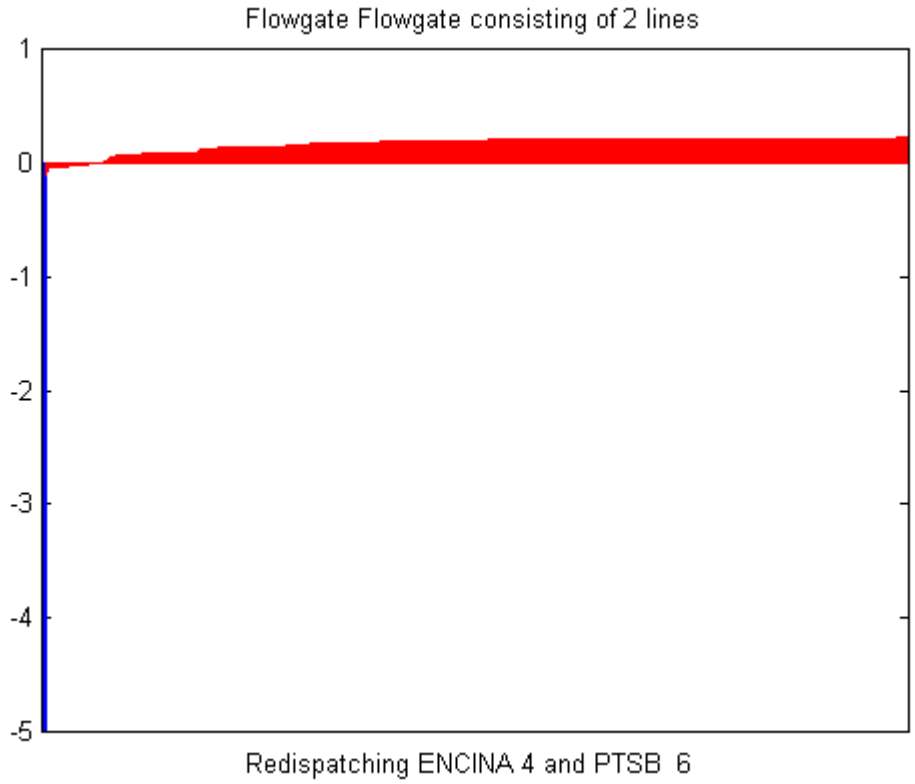

Flowgate Flowgate consisting of 12 lines
0.3
0.25
0.2
0.15
0.1
0.05
0
-0.05
0
500
1000
1500
2000
2500
3000
Redispatching PTSB 6 and DEVERS

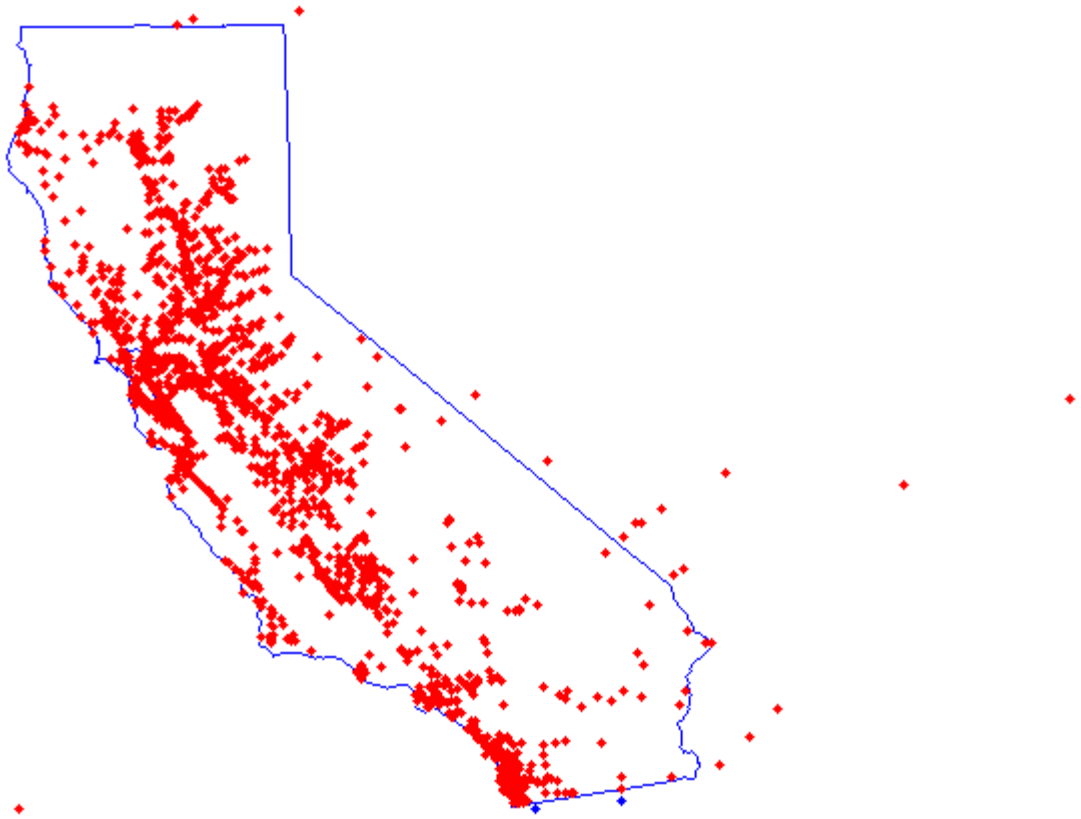


Congestion of the entire CFE interface

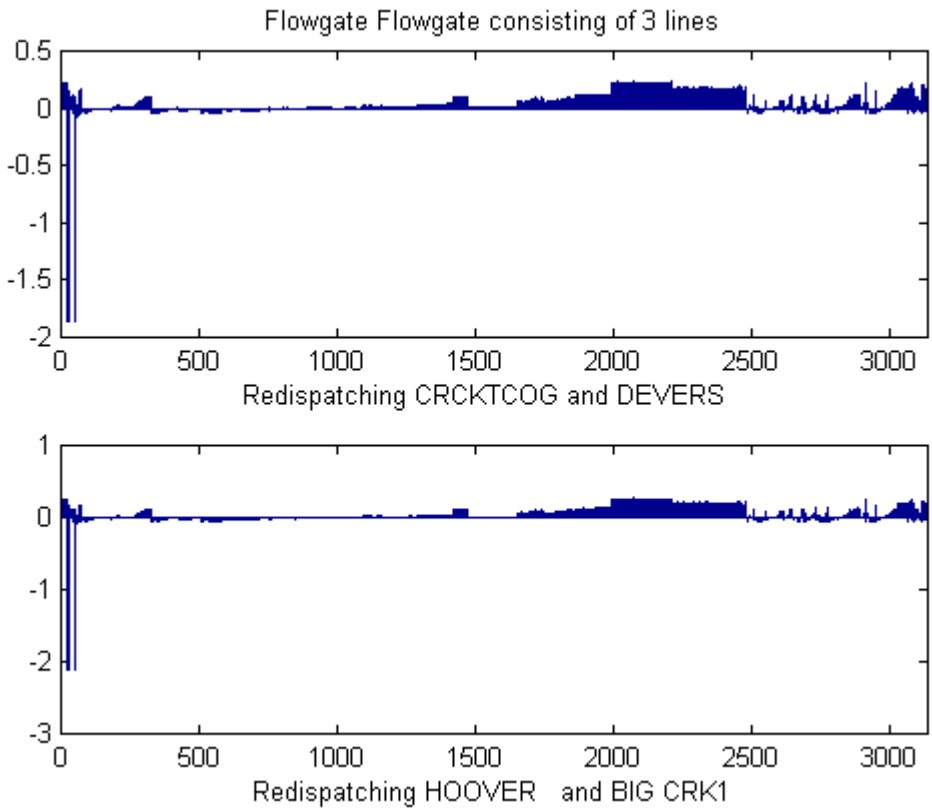


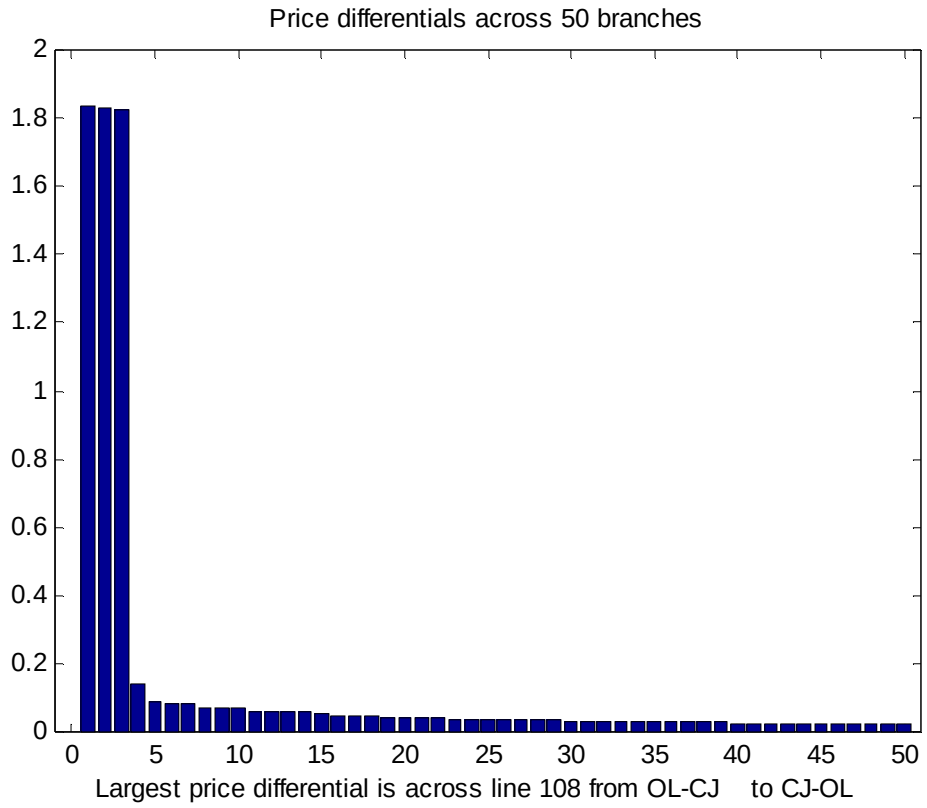

Price differentials across 50 branches
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 22 from IMPRLVLY to ROA

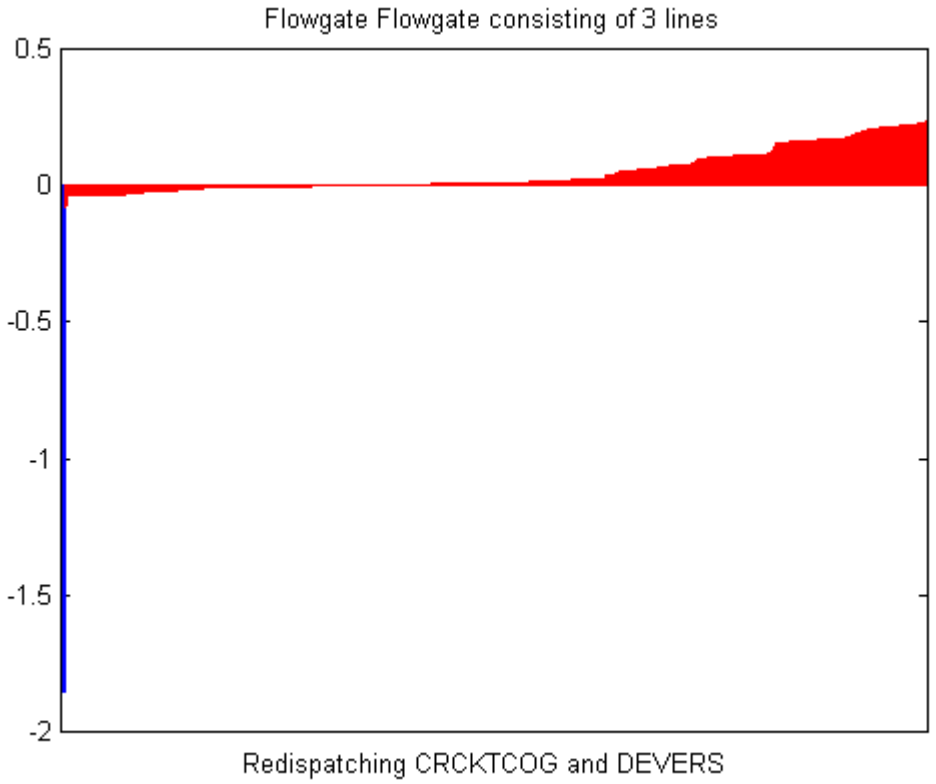

Flowgate Flowgate consisting of 2 lines
1
0
-1
-2
-3
-4
-5
Redispatching ENCINA 4 and PTSB 6

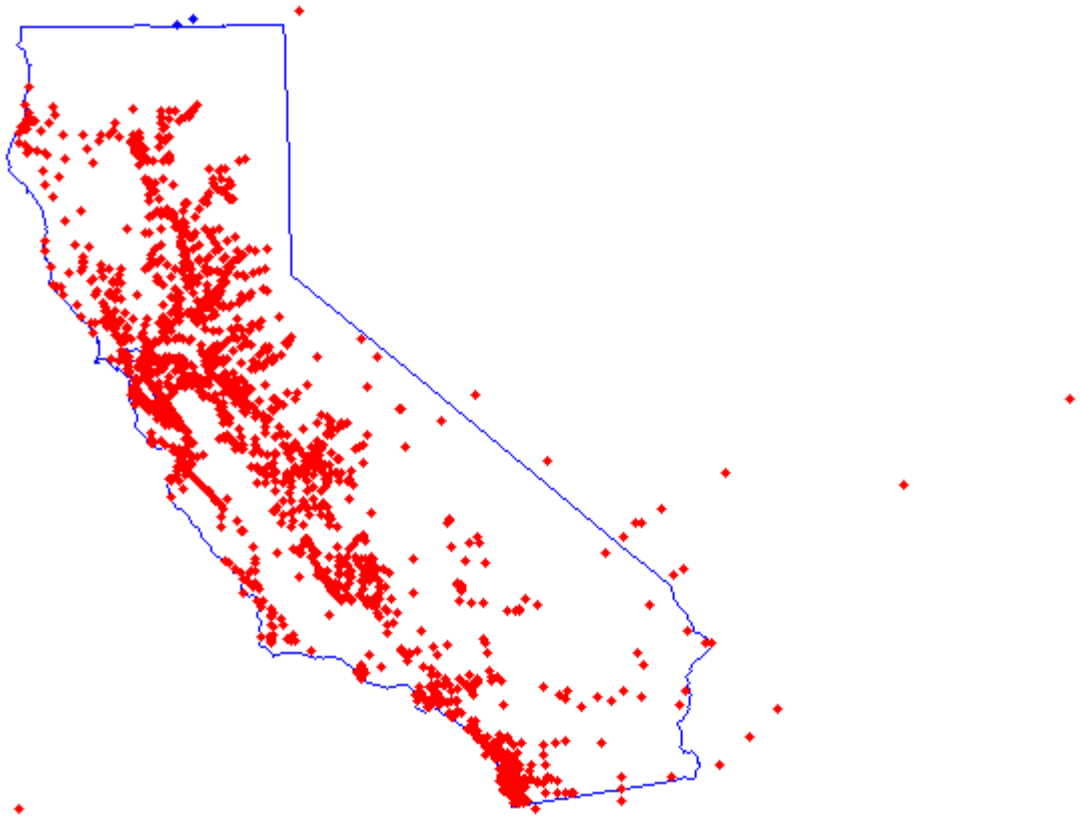


Congestion of the entire COI interface (sum of three lines)

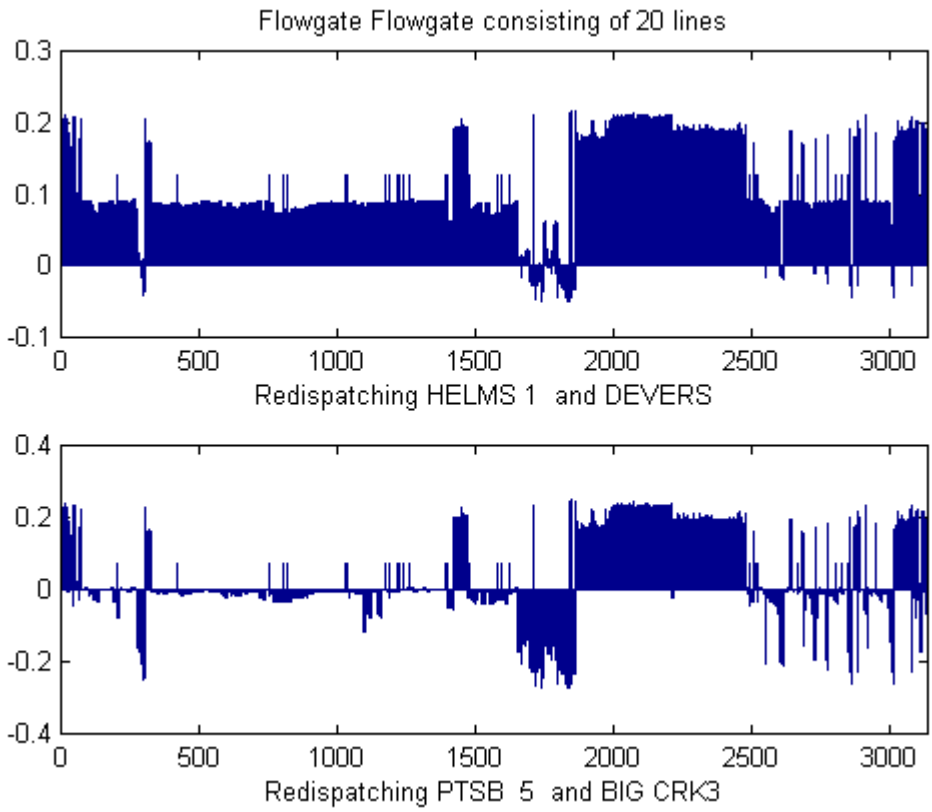


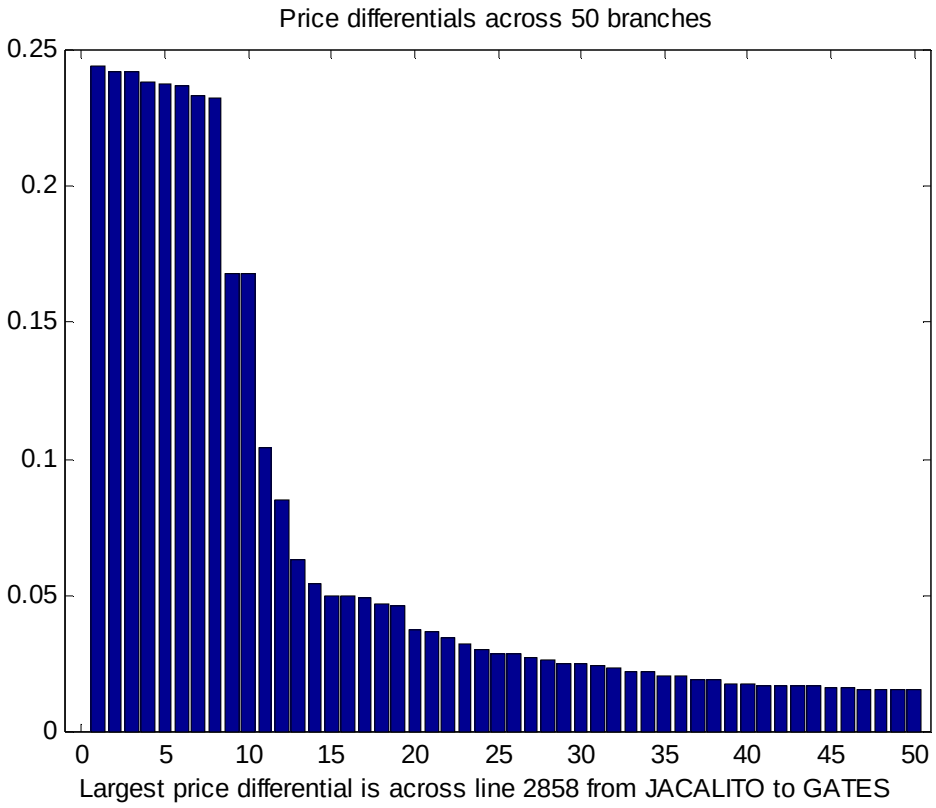

Price differentials across 50 branches
2
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 108 from OL-CJ to CJ-OL

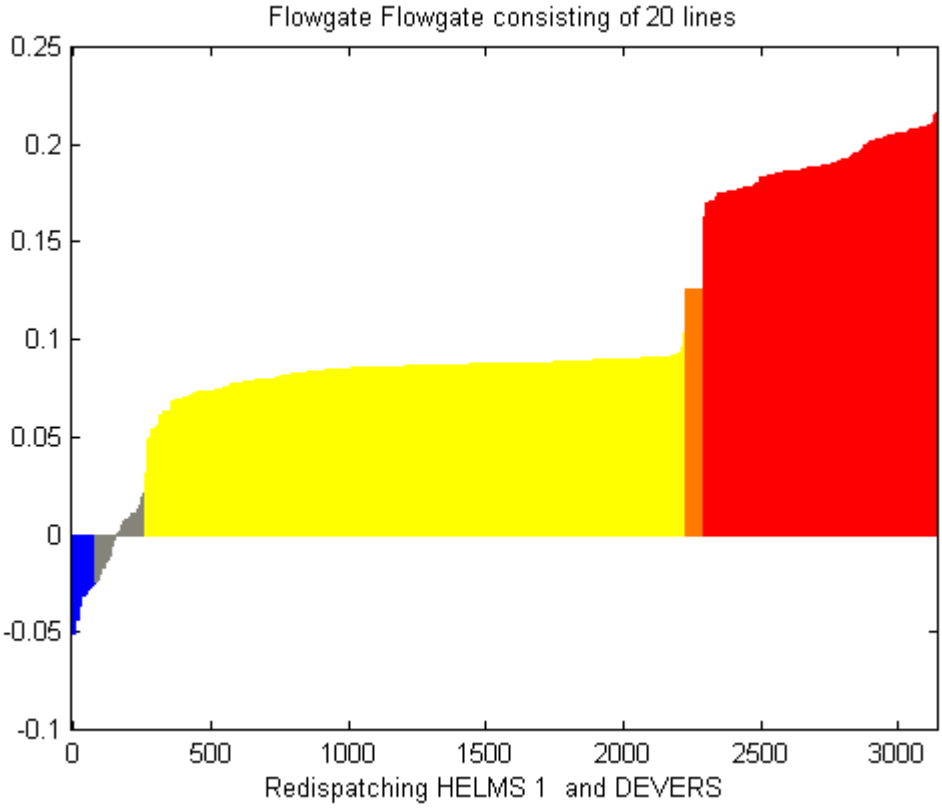

Flowgate Flowgate consisting of 3 lines
0.5
0
-0.5
-1
-1.5
-2
Redispatching CRCKTCOG and DEVERS

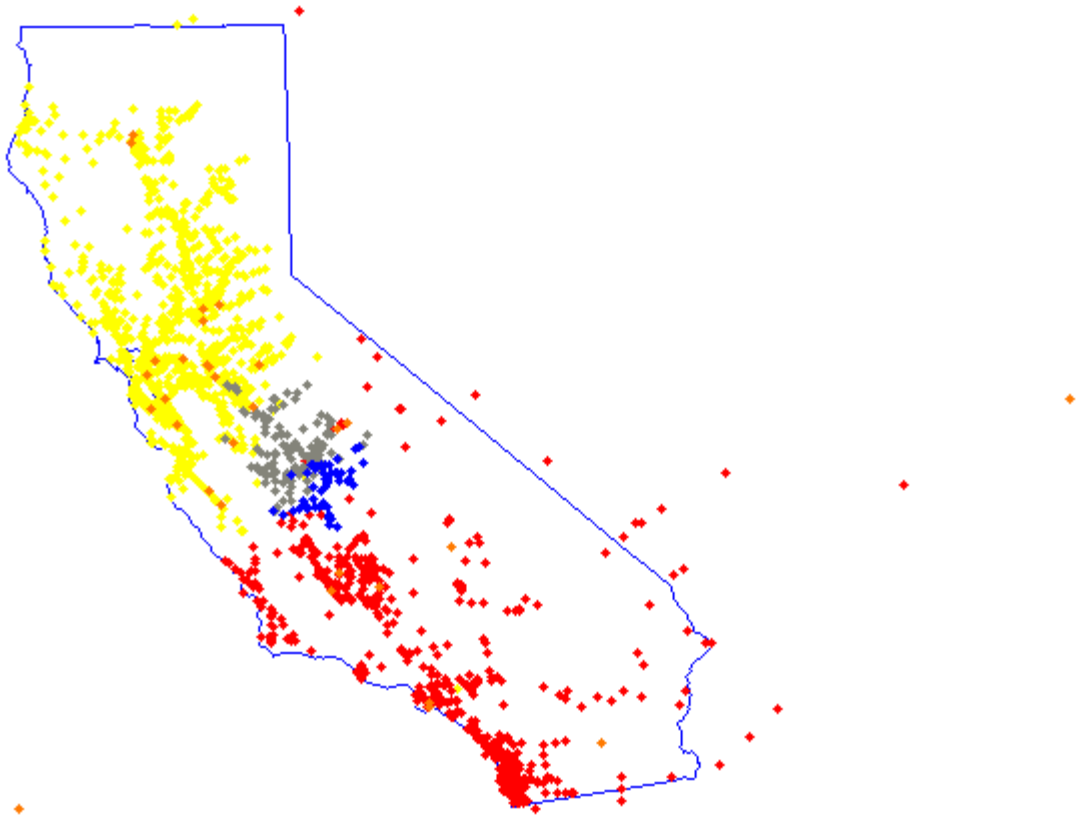


Congestion of a flowgate based on the sum of all imports into Fresno

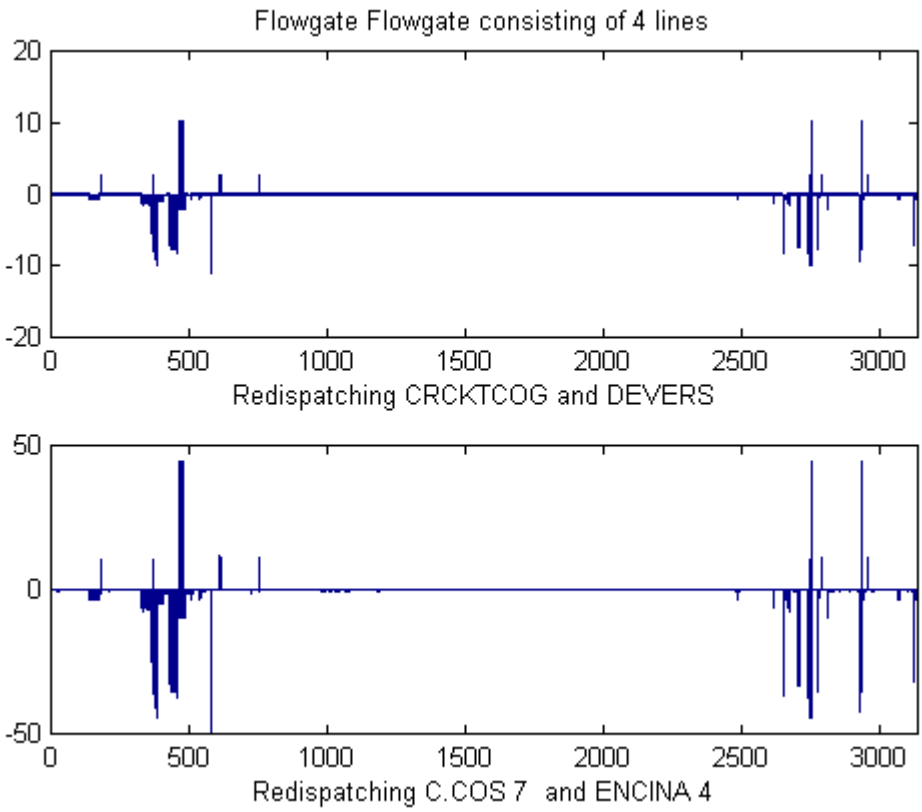


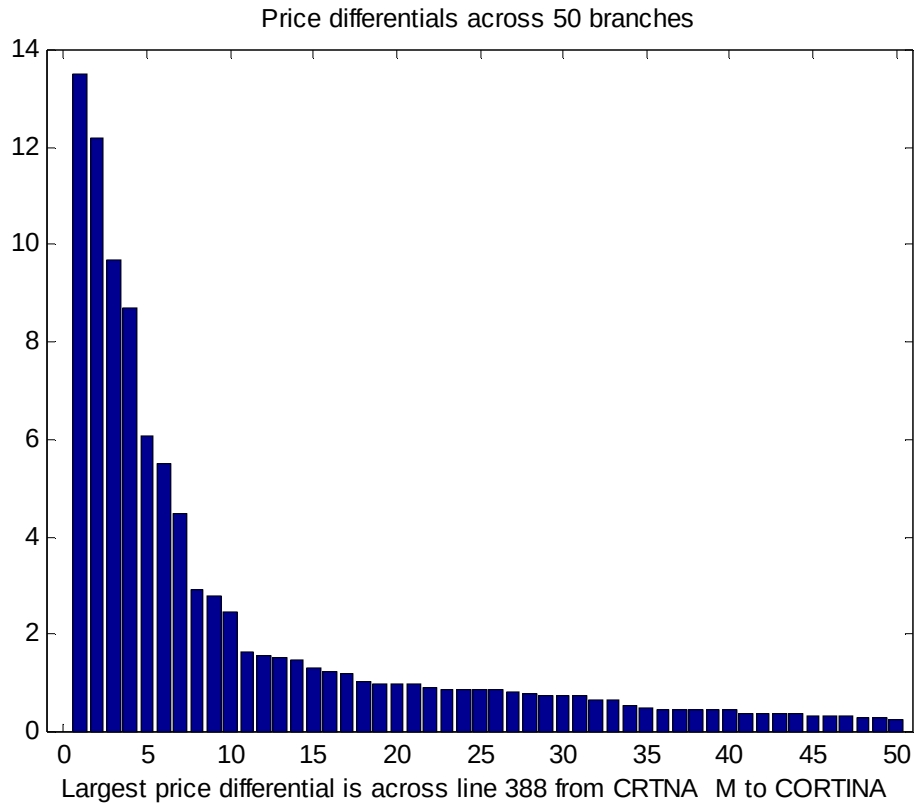

Price differentials across 50 branches
0.25
0.2
0.15
0.1
0.05
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 2858 from JACALITO to GATES

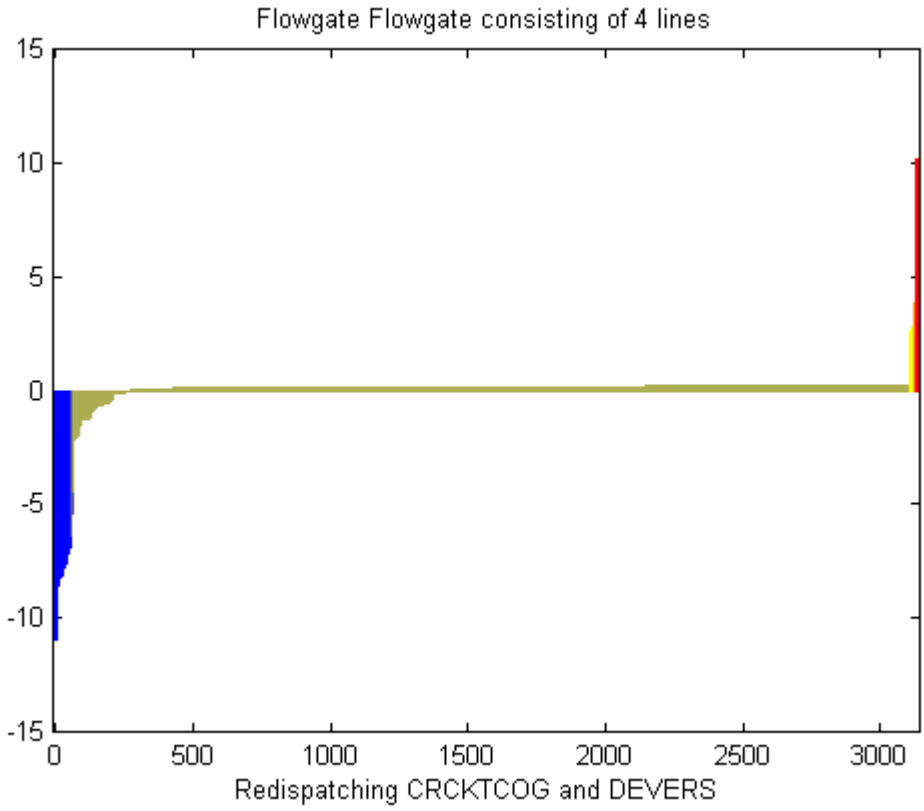

Flowgate Flowgate consisting of 20 lines
0.25
0.2
0.15
0.1
0.05
0
-0.05
-0.1
0
500
1000
1500
2000
2500
3000
Redispatching HELMS 1 and DEVERS

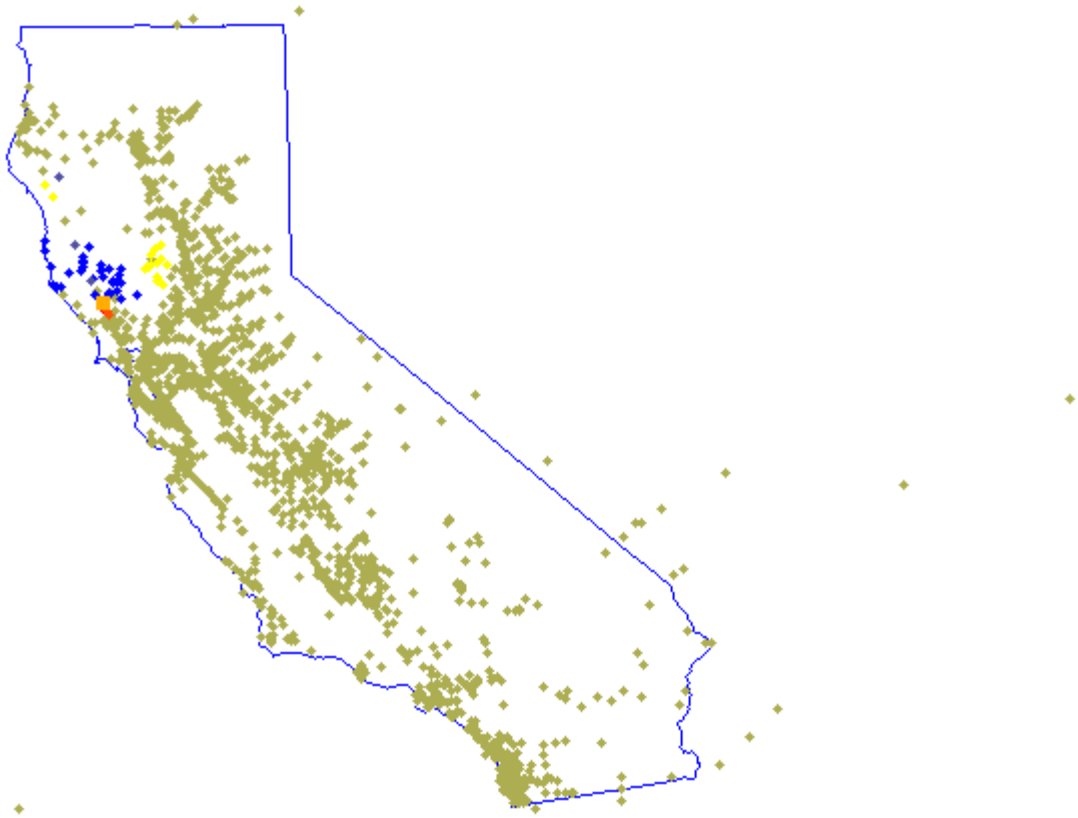


North Bay flowgate consisting of entire import into zone

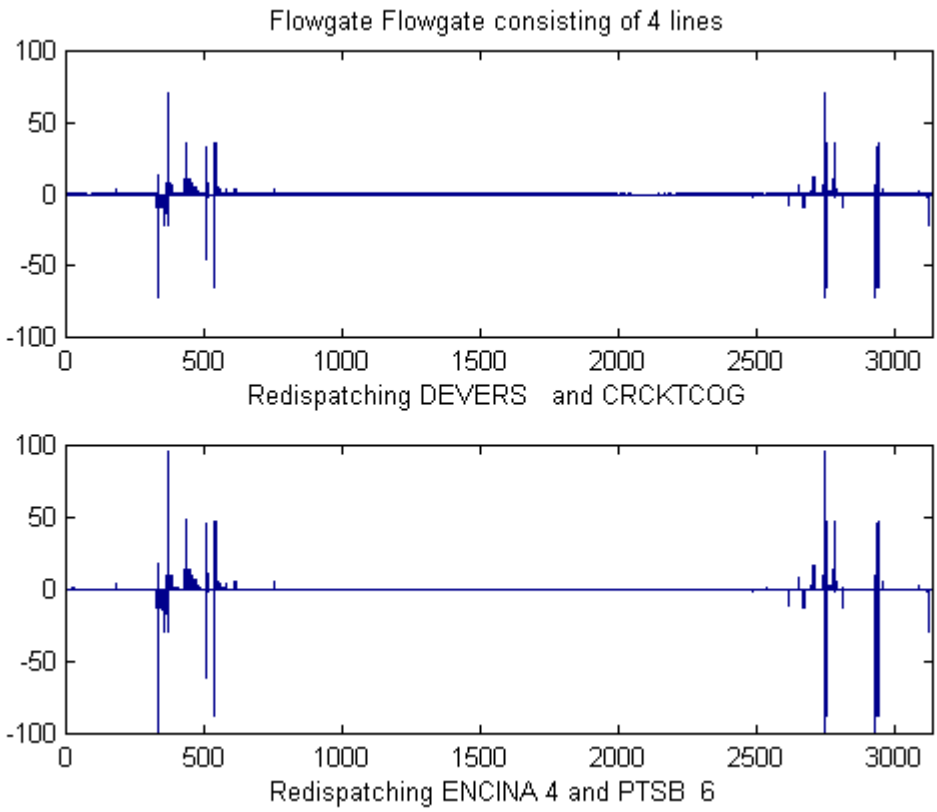


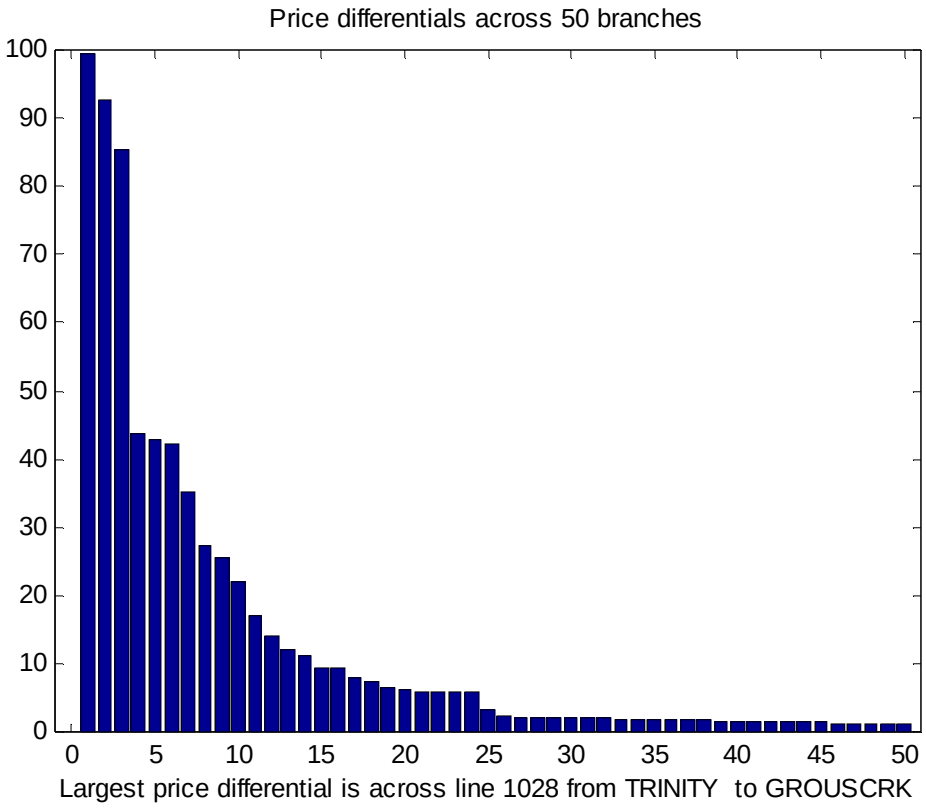

Price differentials across 50 branches
14
12
10
8
6
4
2
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 388 from CRTNA M to CORTINA

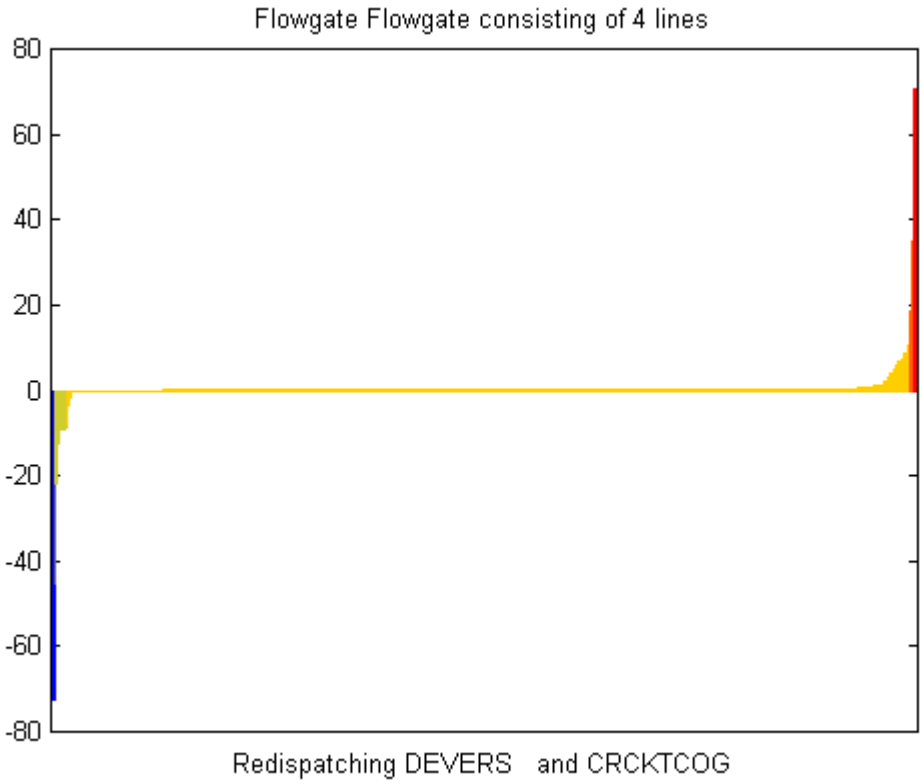

Flowgate Flowgate consisting of 4 lines
15
10
5
0
-5
-10
-15
0
500
1000
1500
2000
2500
3000
Redispatching CRCKTCOG and DEVERS

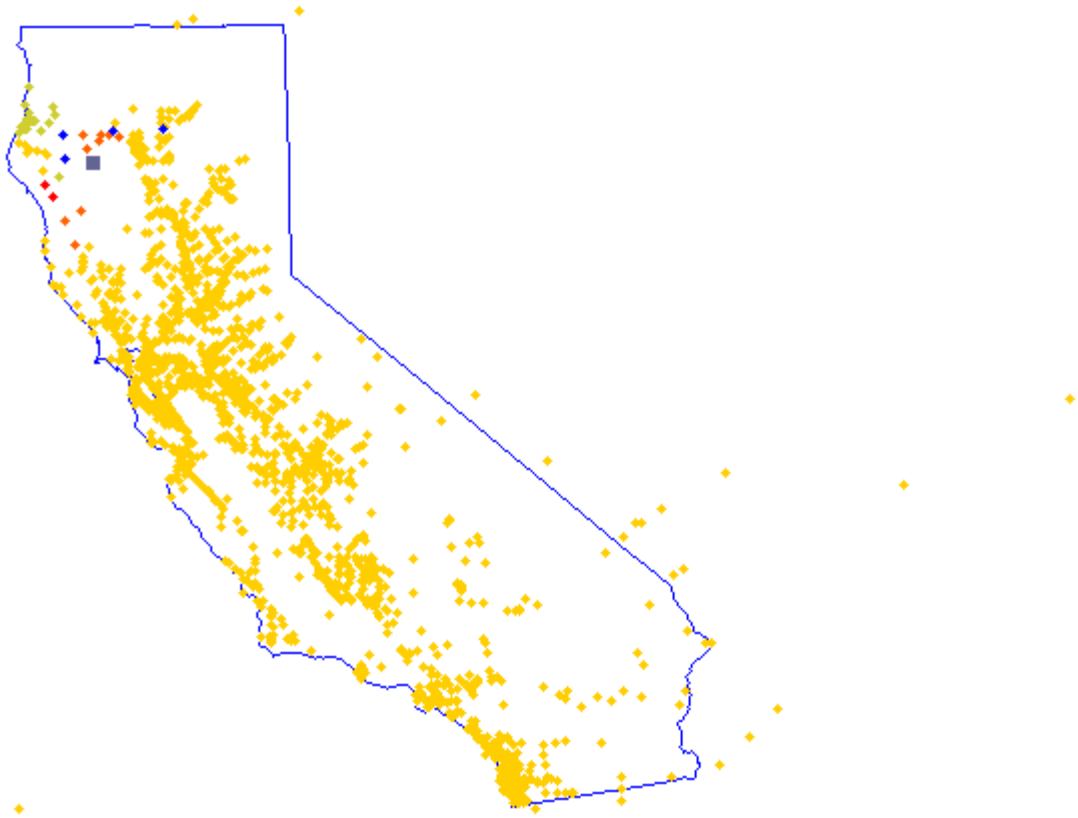


Humboldt flowgate defined as the total import into the zone

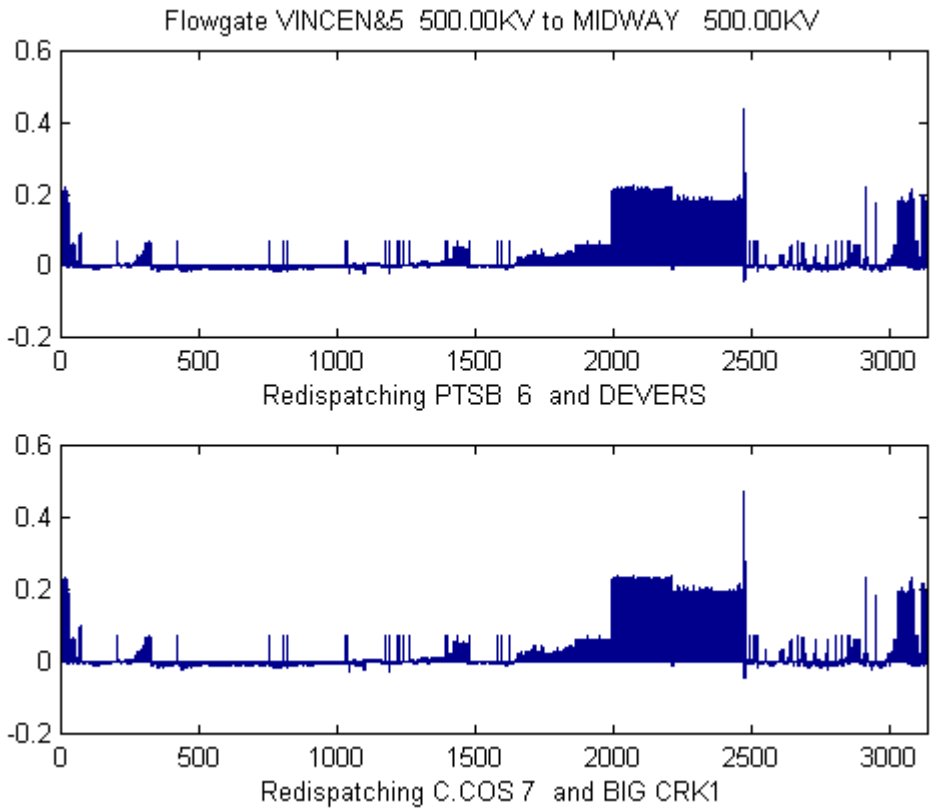


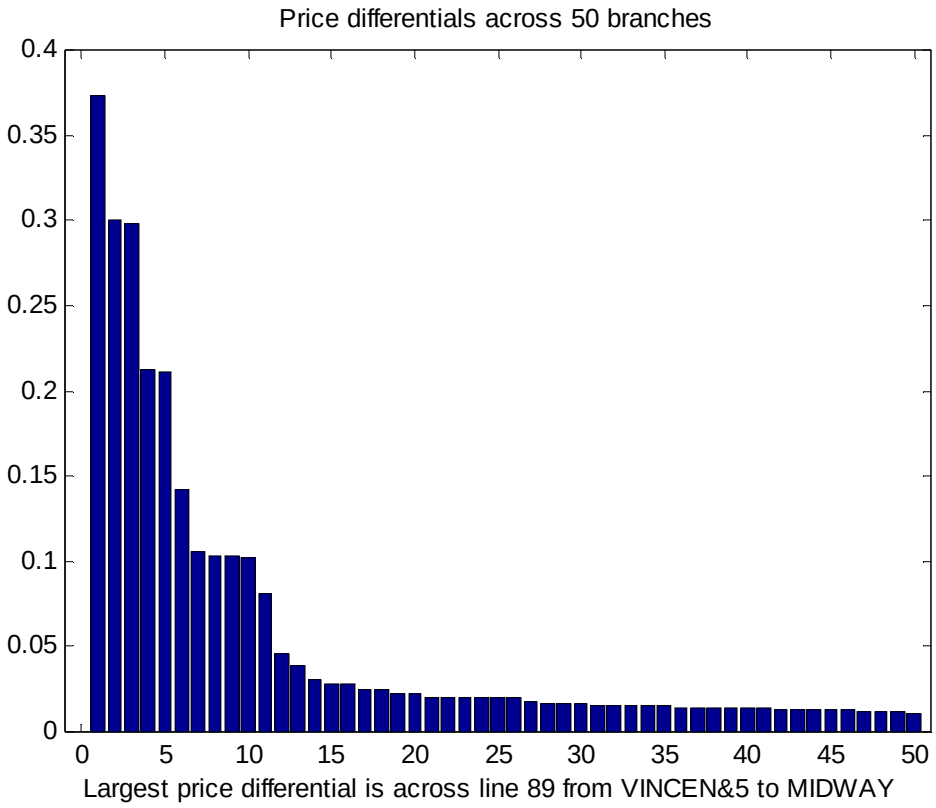

Price differentials across 50 branches
100
90
80
70
60
50
40
30
20
10
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 1028 from TRINITY to GROUSCRK

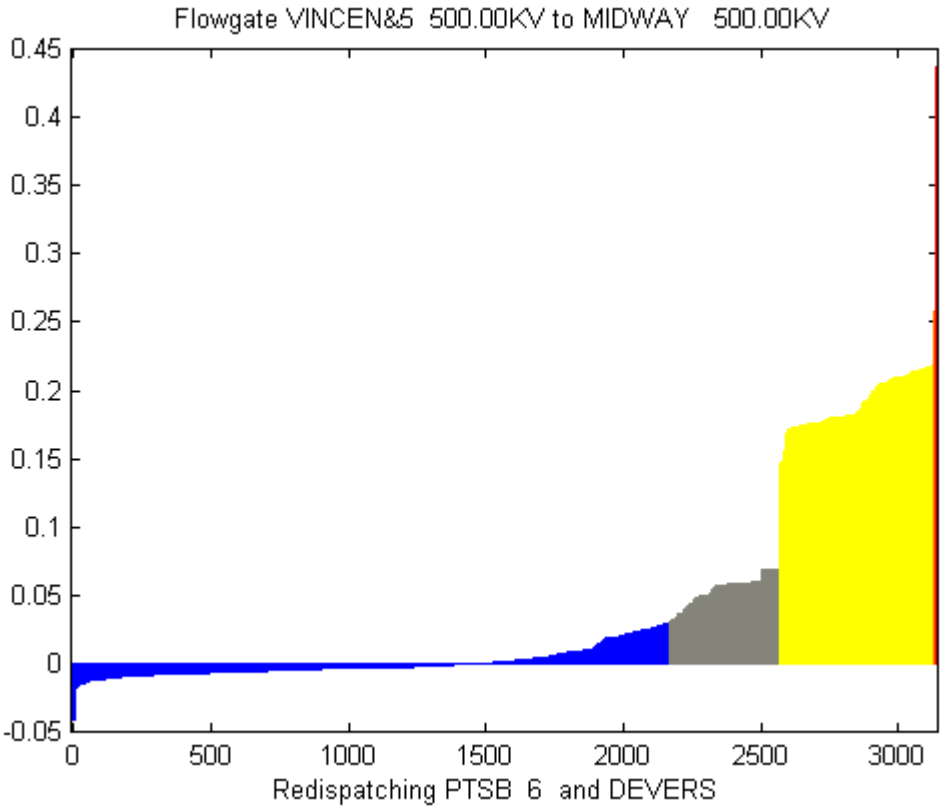

Flowgate Flowgate consisting of 4 lines
80
60
40
20
0
-20
-40
-60
-80
Redispatching DEVERS and CRCKTCOG

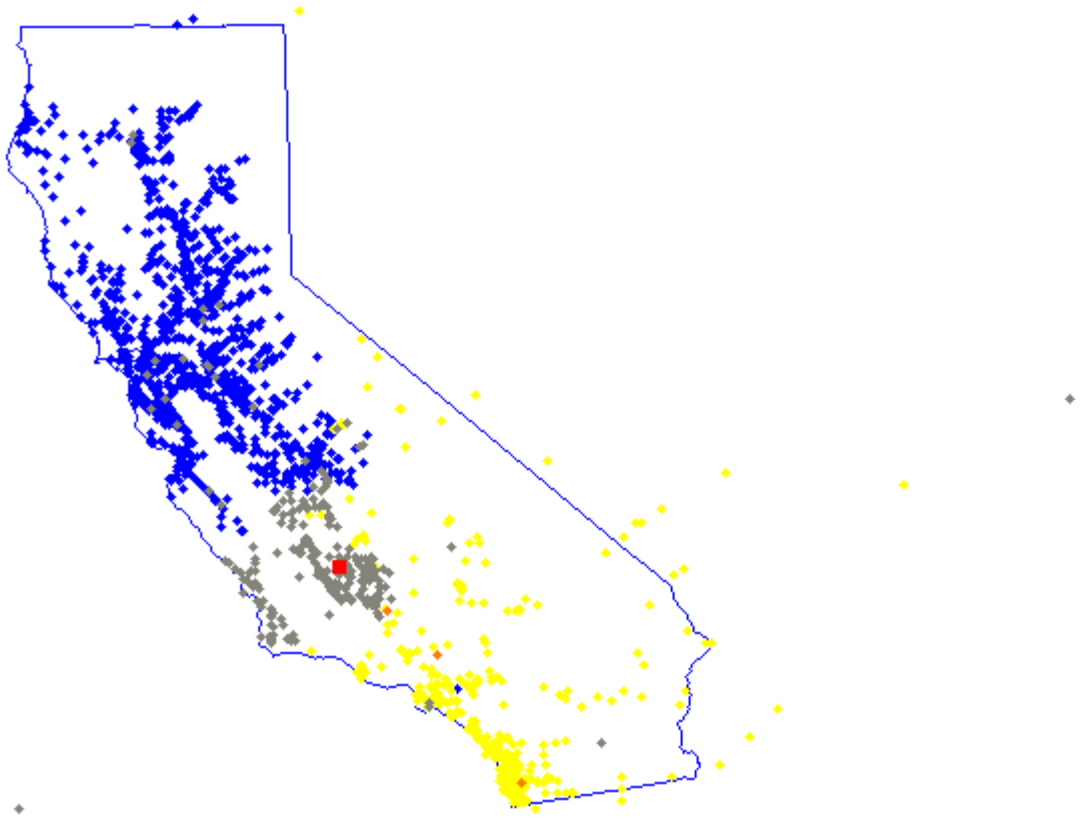


Congestion on Path 26,

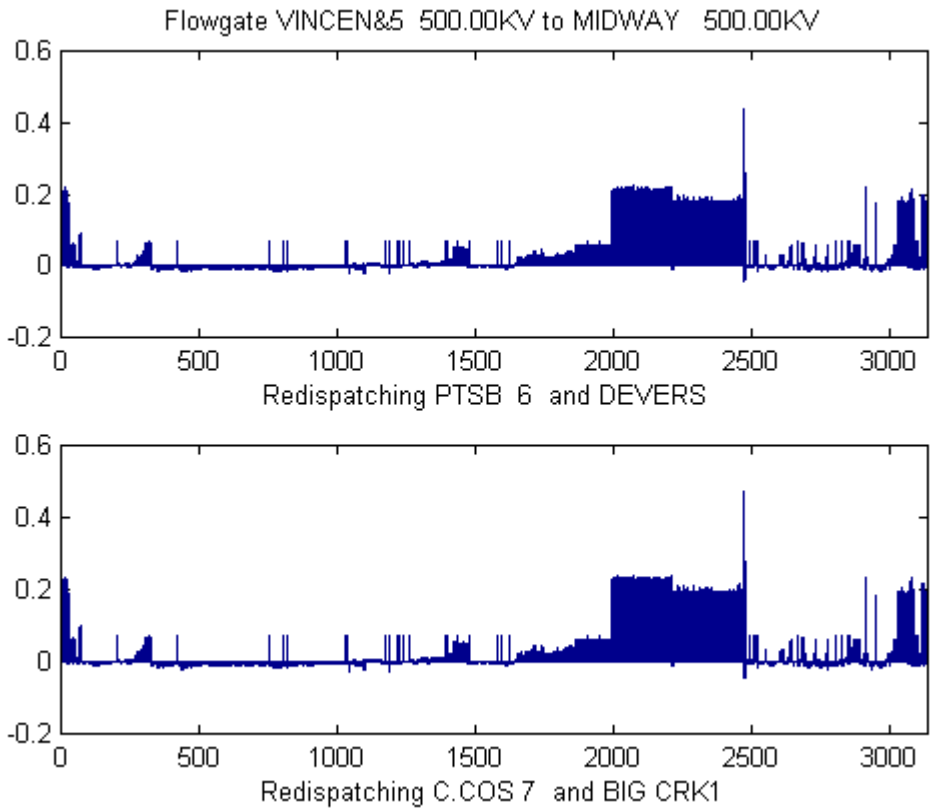


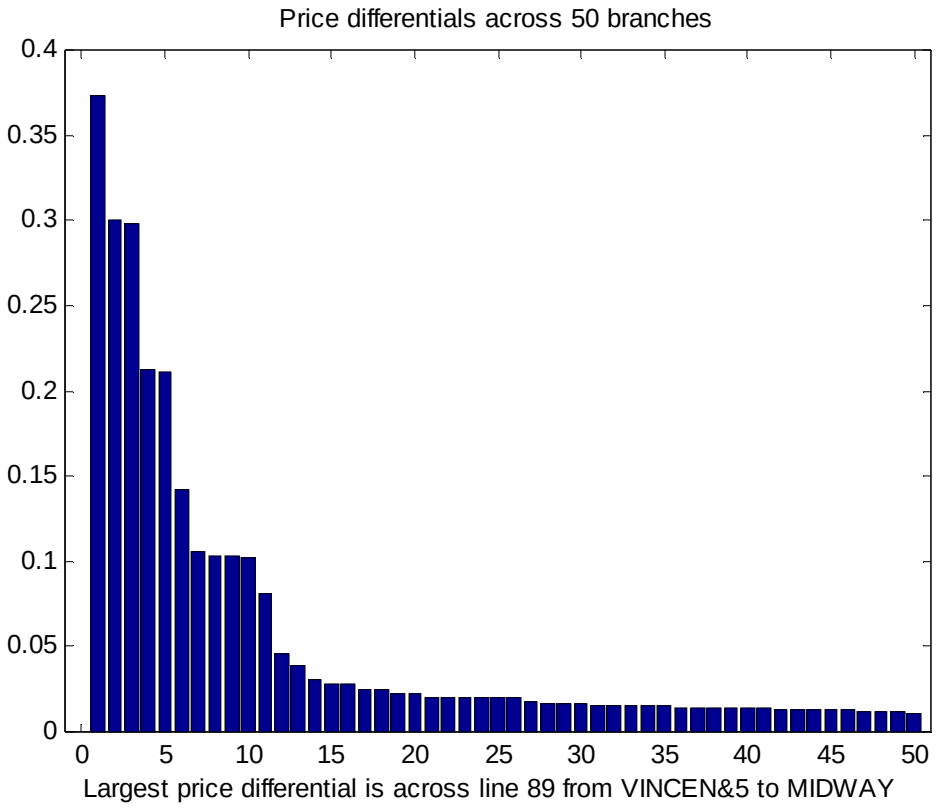

Price differentials across 50 branches
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 89 from VINCEN&5 to MIDWAY

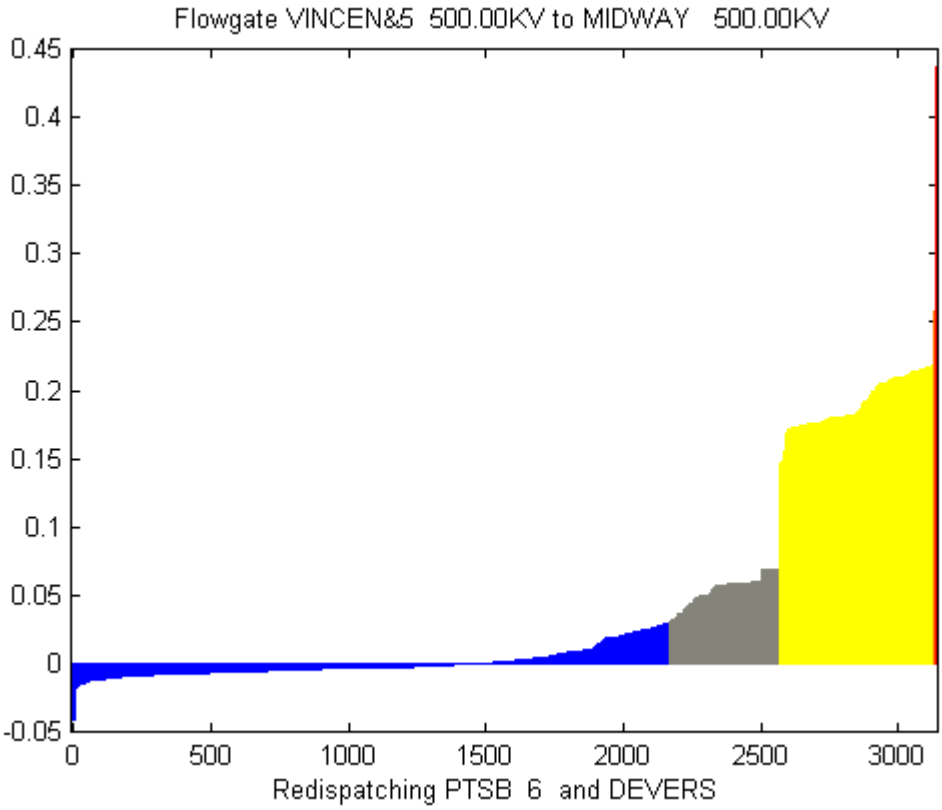

Flowgate VINCEN&5 500.00KV to MIDWAY 500.00KV
0.45
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
-0.05
0
500
1000
1500
2000
2500
3000
Redispatching PTSB 6 and DEVERS

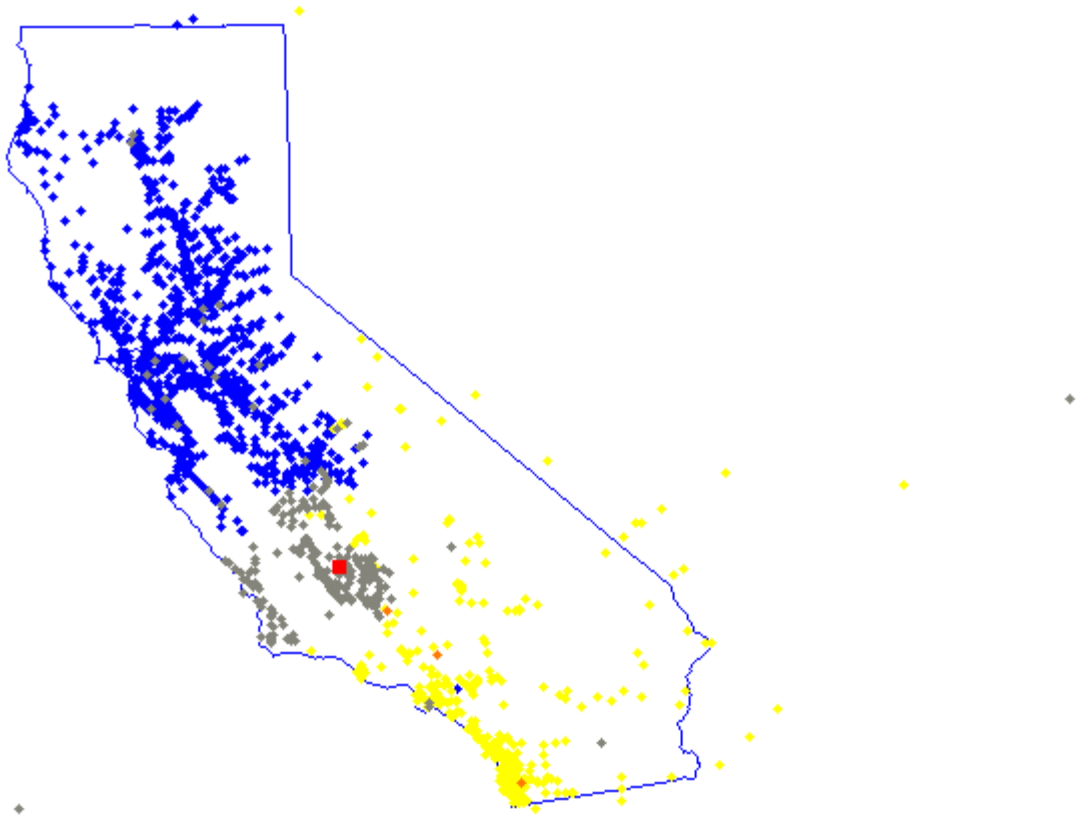


Congestion on Path 26

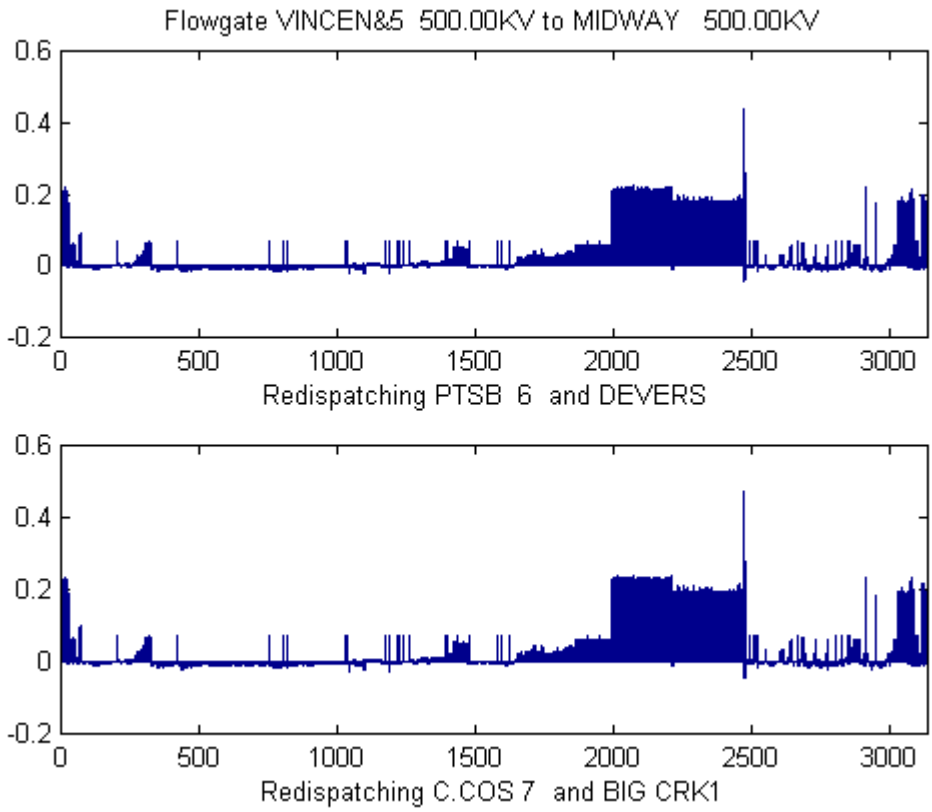


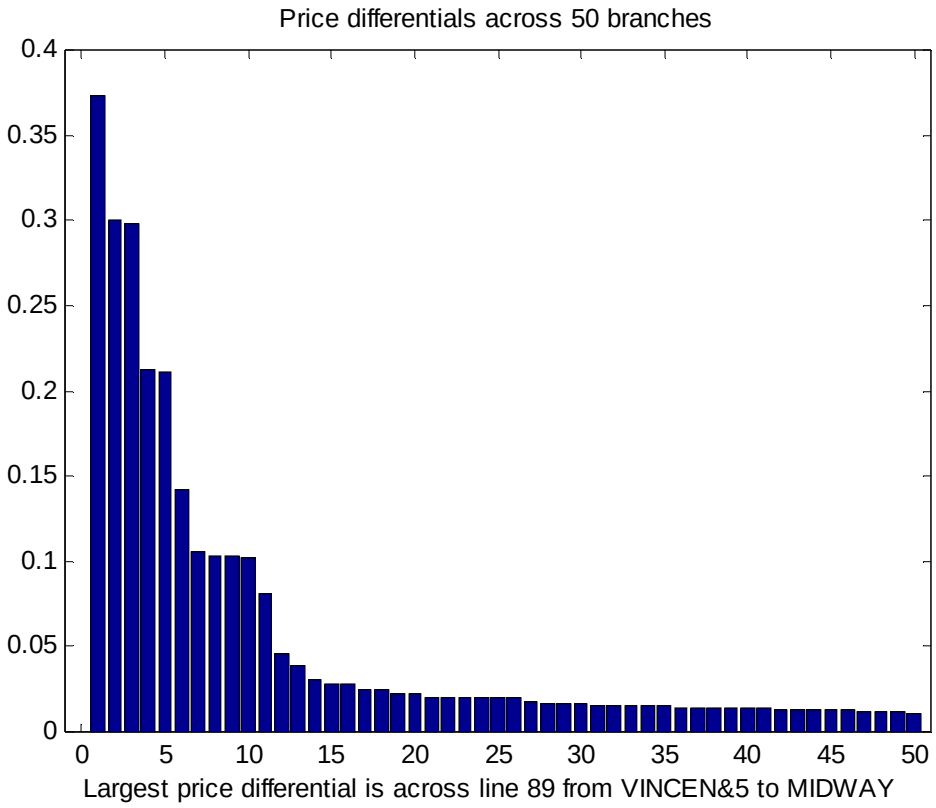

Price differentials across 50 branches
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 89 from VINCEN&5 to MIDWAY

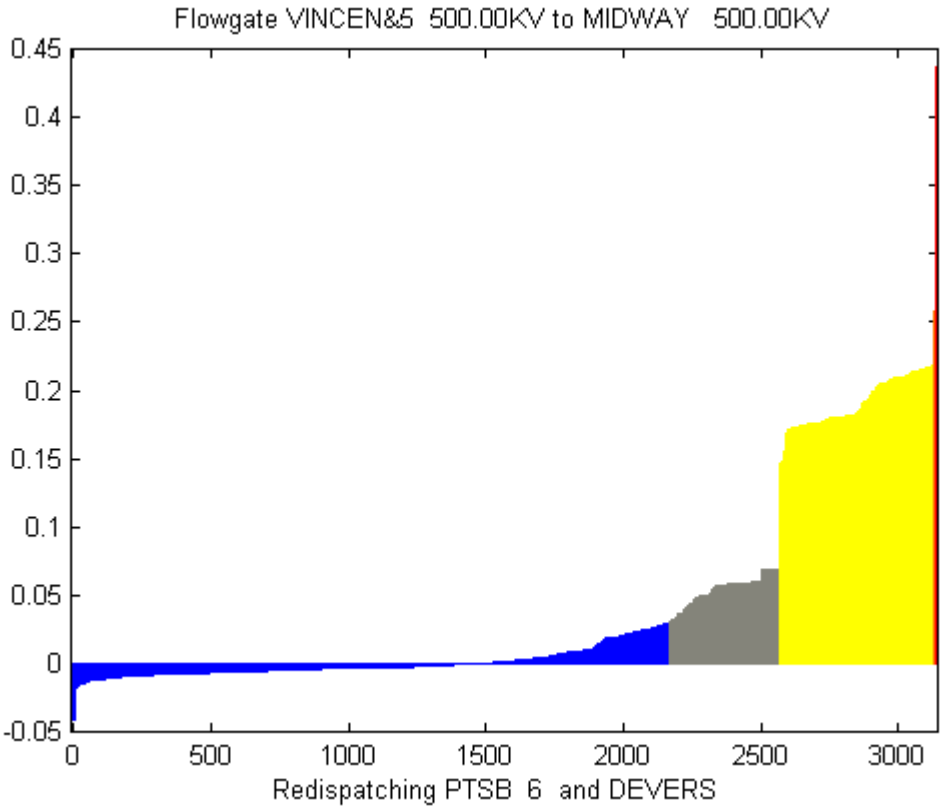

Flowgate VINCEN&5 500.00KV to MIDWAY 500.00KV
0.45
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
-0.05
0
500
1000
1500
2000
2500
3000
Redispatching PTSB 6 and DEVERS

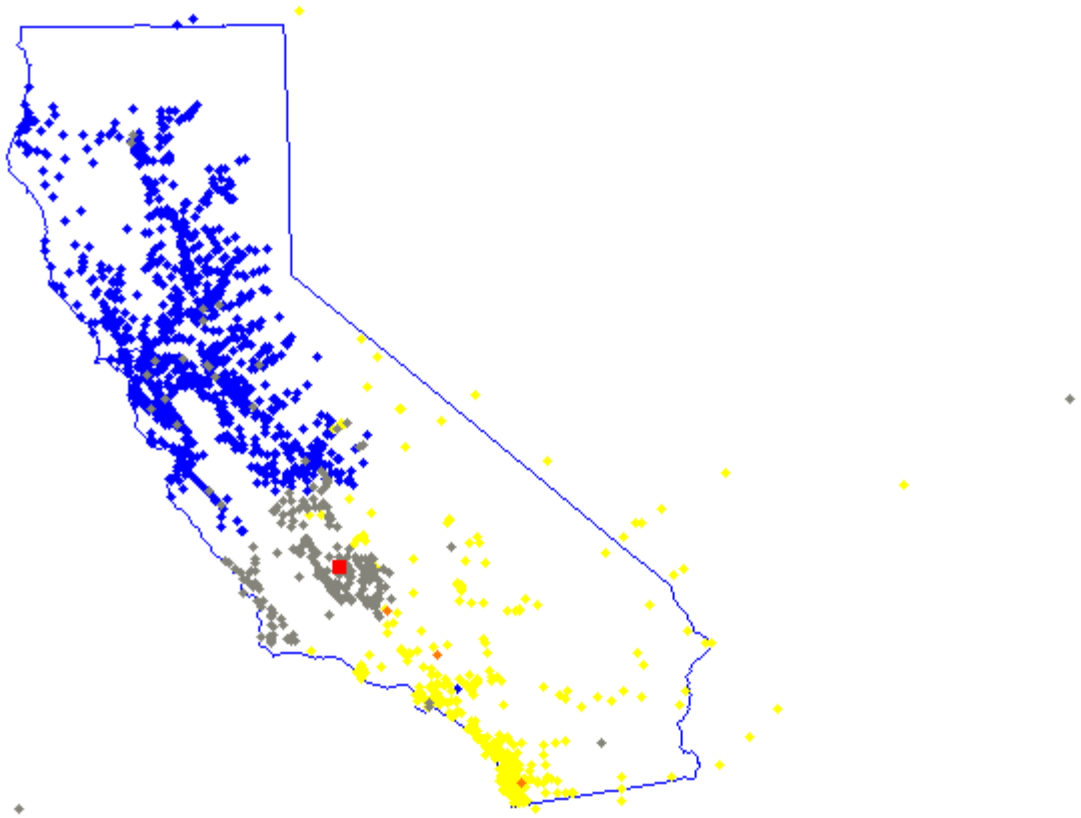


Congestion within Path 26

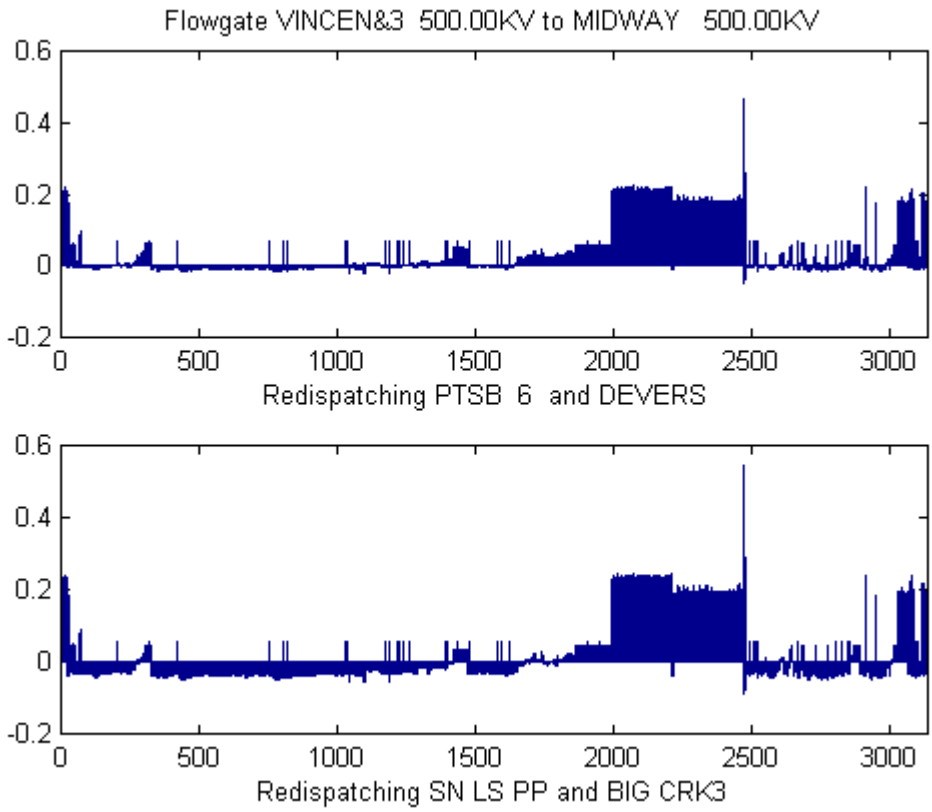


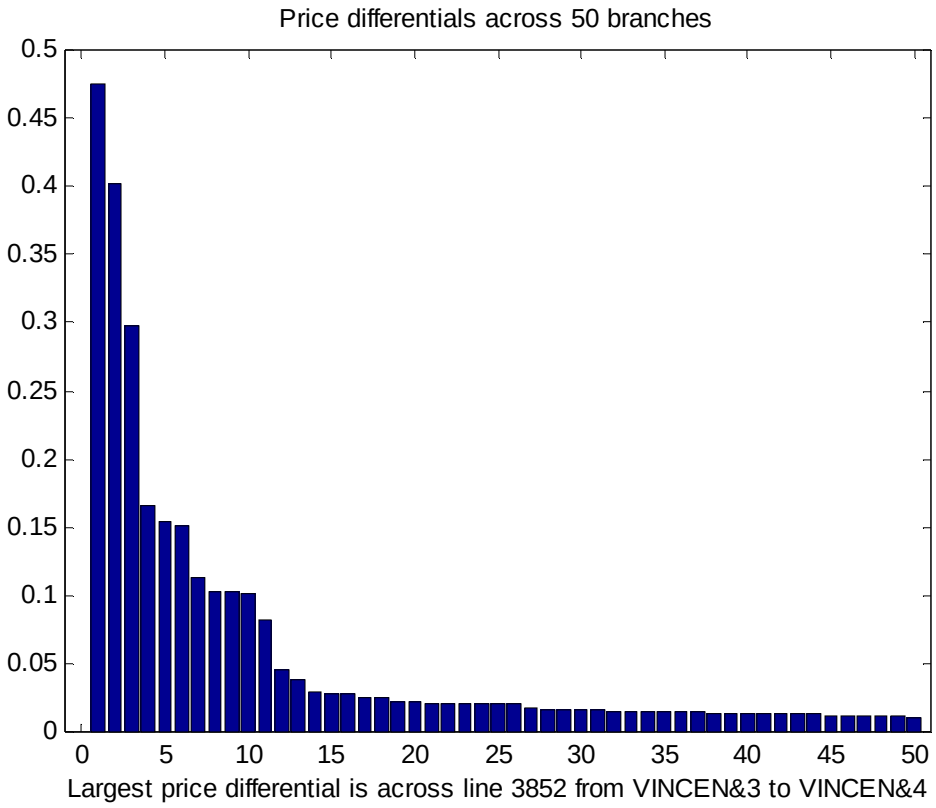

Price differentials across 50 branches
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 89 from VINCEN&5 to MIDWAY

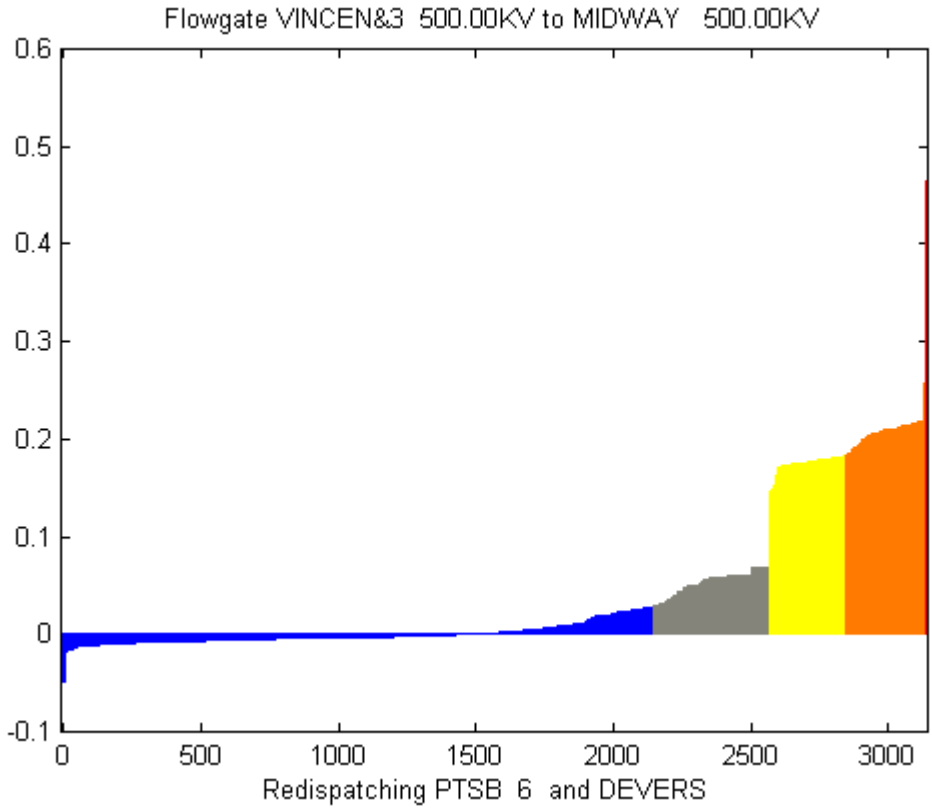

Flowgate VINCEN&5 500.00KV to MIDWAY 500.00KV
0.45
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
-0.05
0
500
1000
1500
2000
2500
3000
Redispatching PTSB 6 and DEVERS

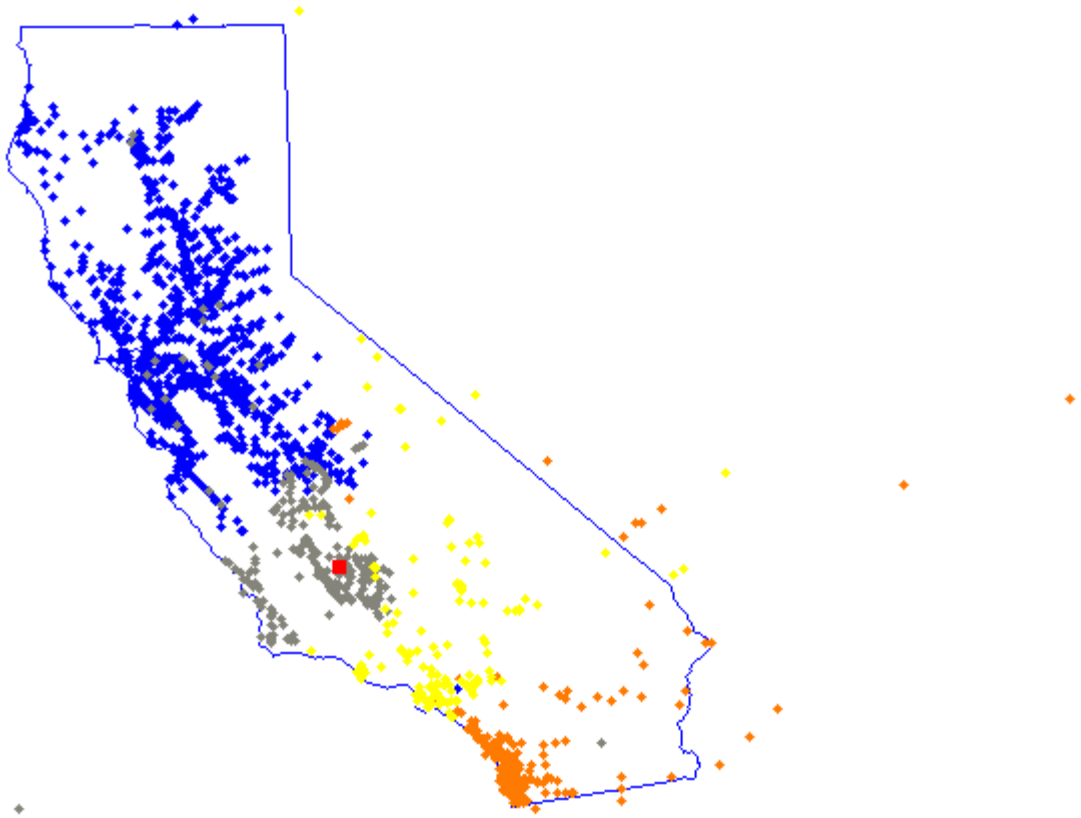


Congestion on Path 26

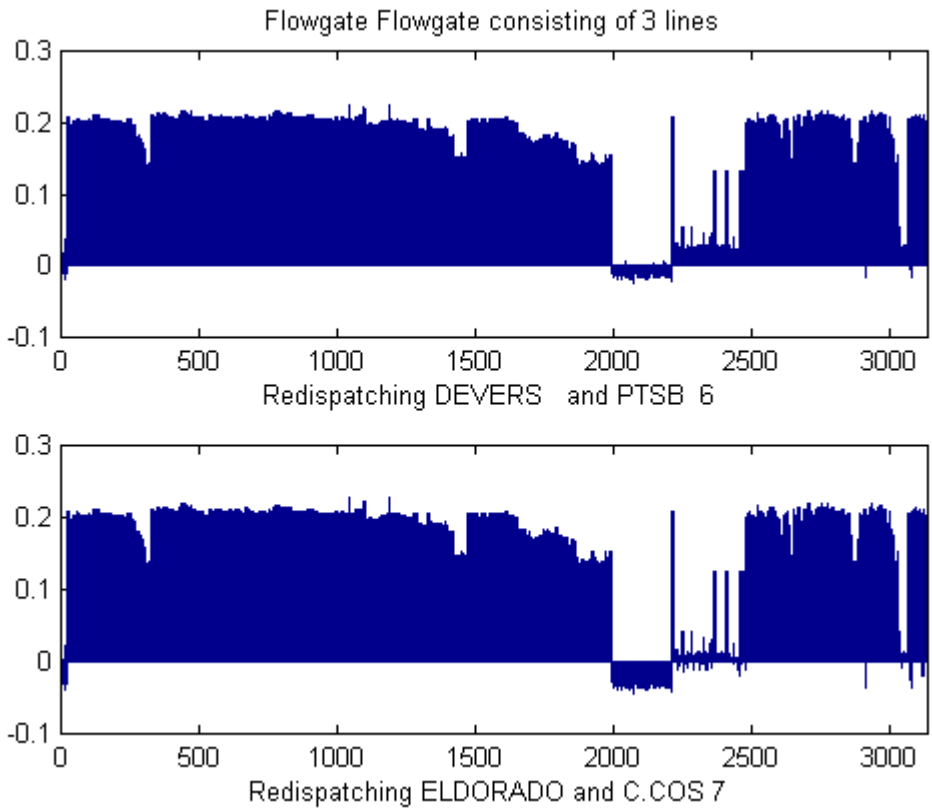


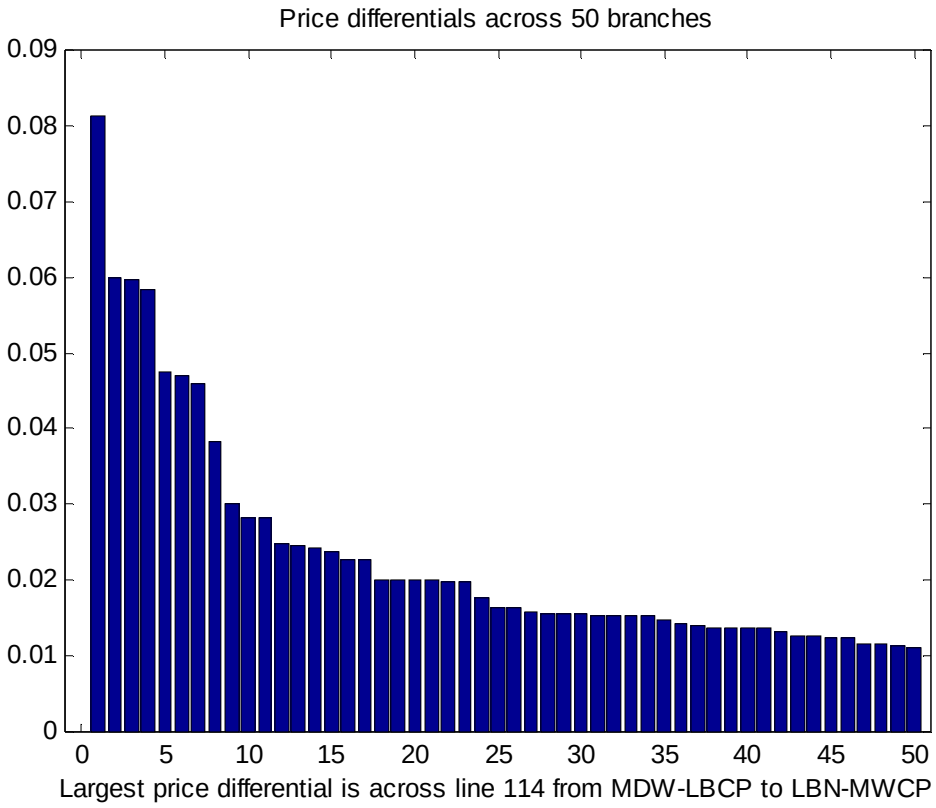

Price differentials across 50 branches
0.5
0.45
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 3852 from VINCEN&3 to VINCEN&4

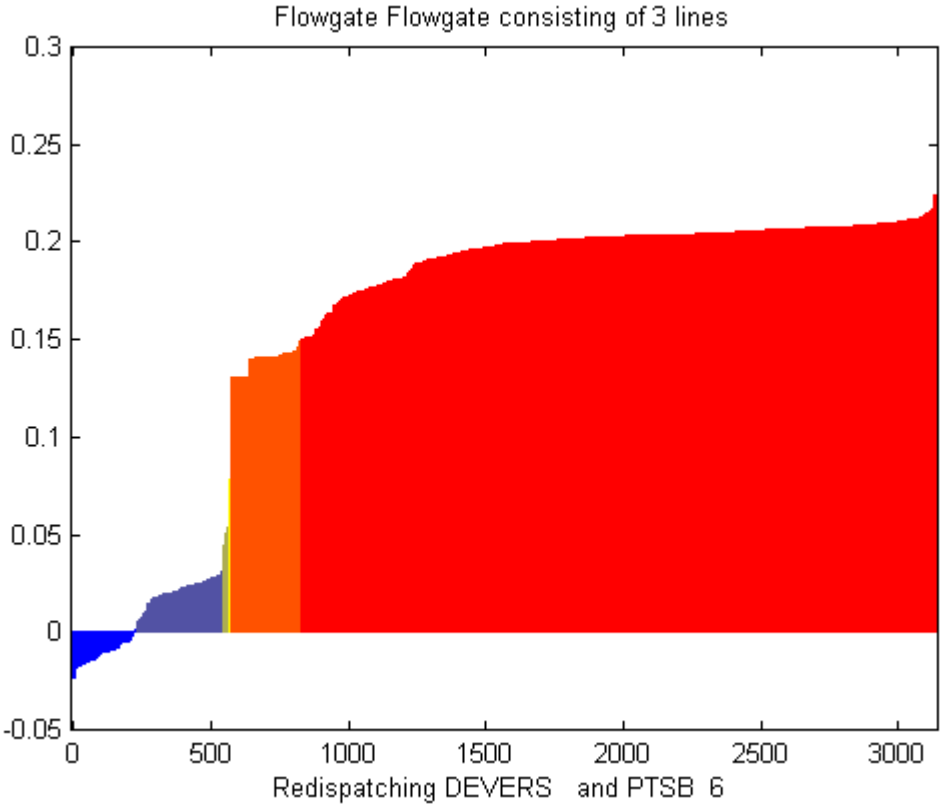

Flowgate VINCEN&3 500.00KV to MIDWAY 500.00KV
0.6
0.5
0.4
0.3
0.2
0.1
0
-0.1
0
500
1000
1500
2000
2500
3000
Redispatching PTSB 6 and DEVERS

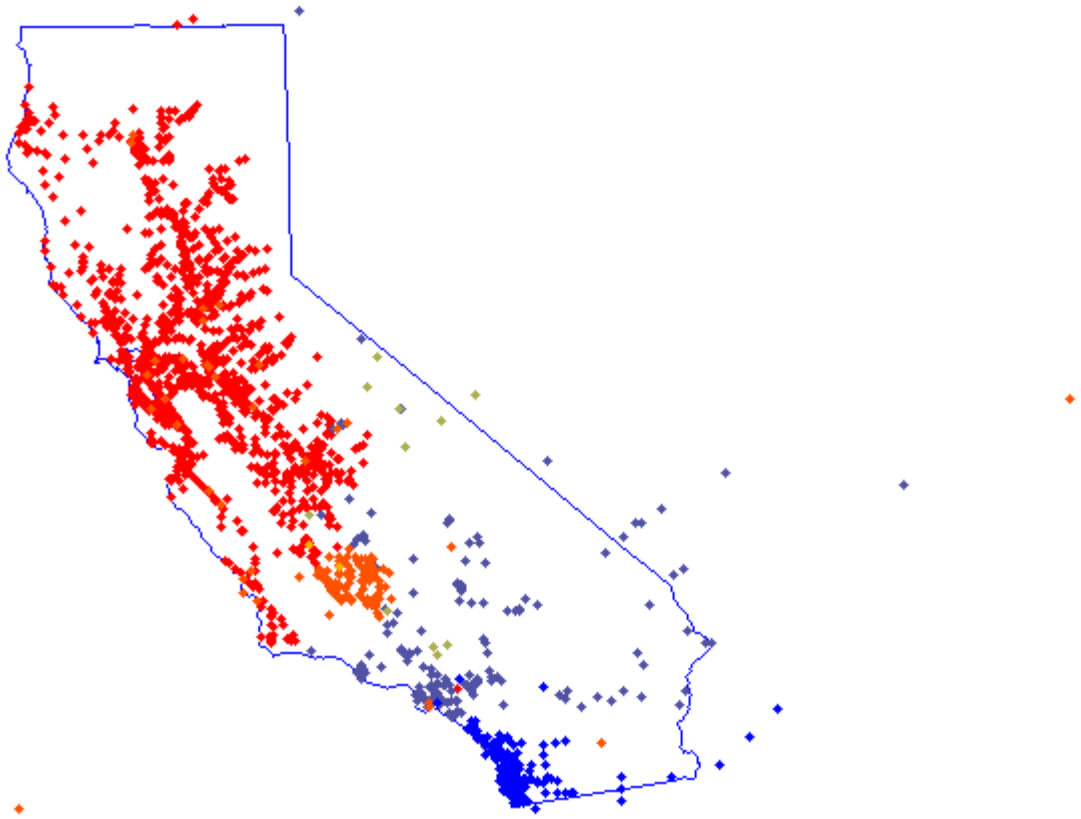


Flowgate on Path 26

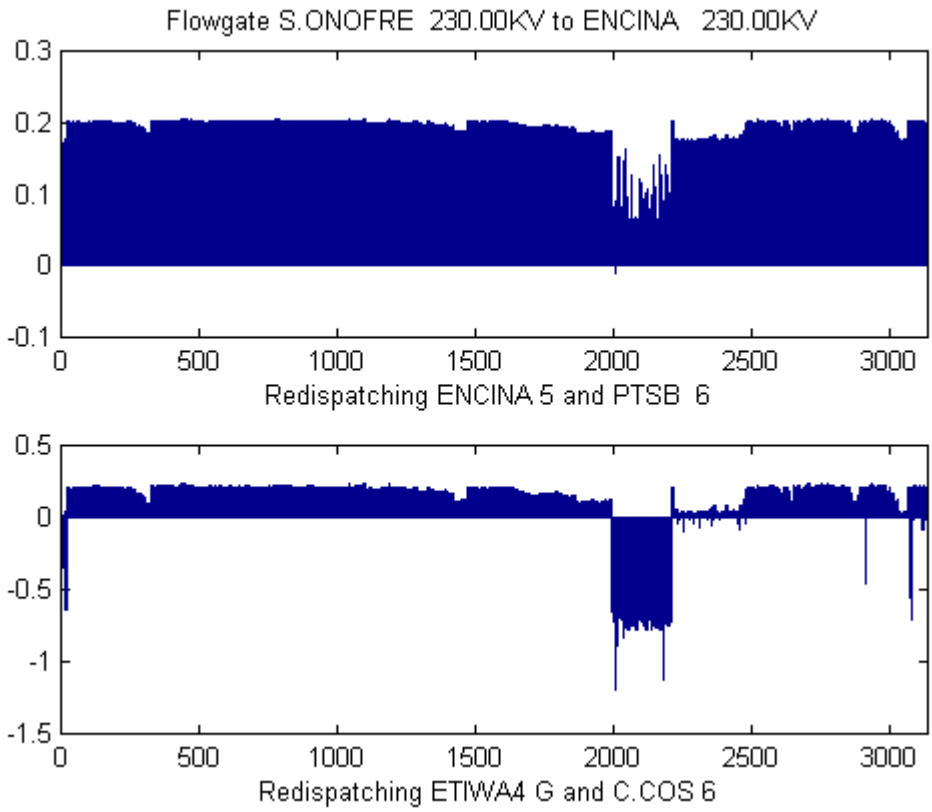


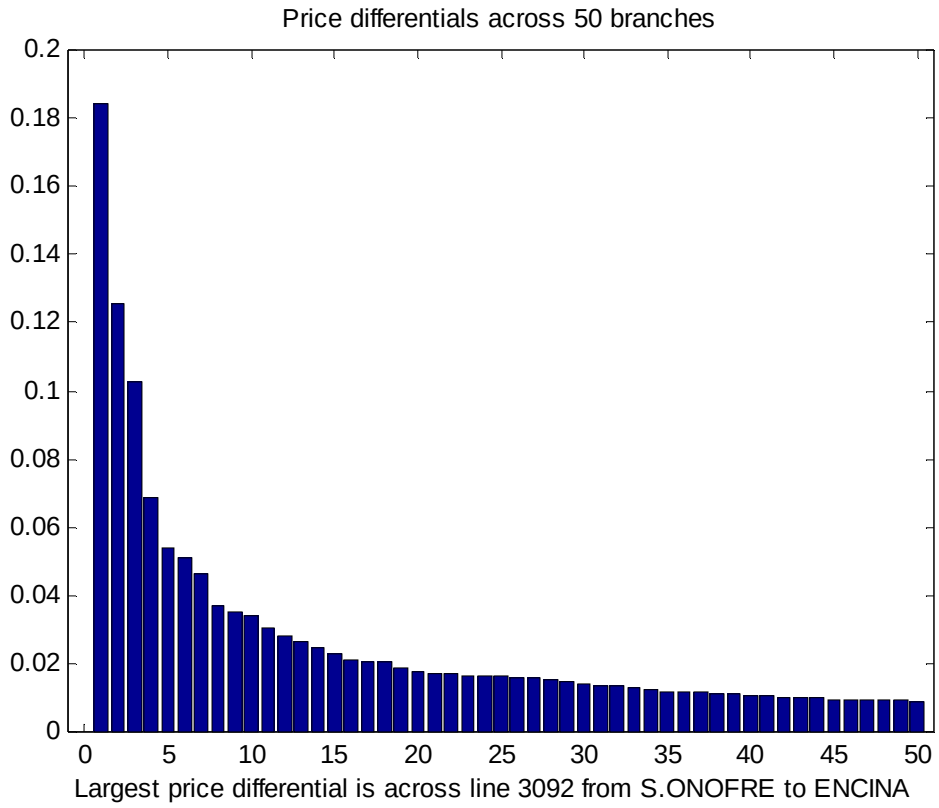

Price differentials across 50 branches
0.09
0.08
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 114 from MDW-LBCP to LBN-MWCP

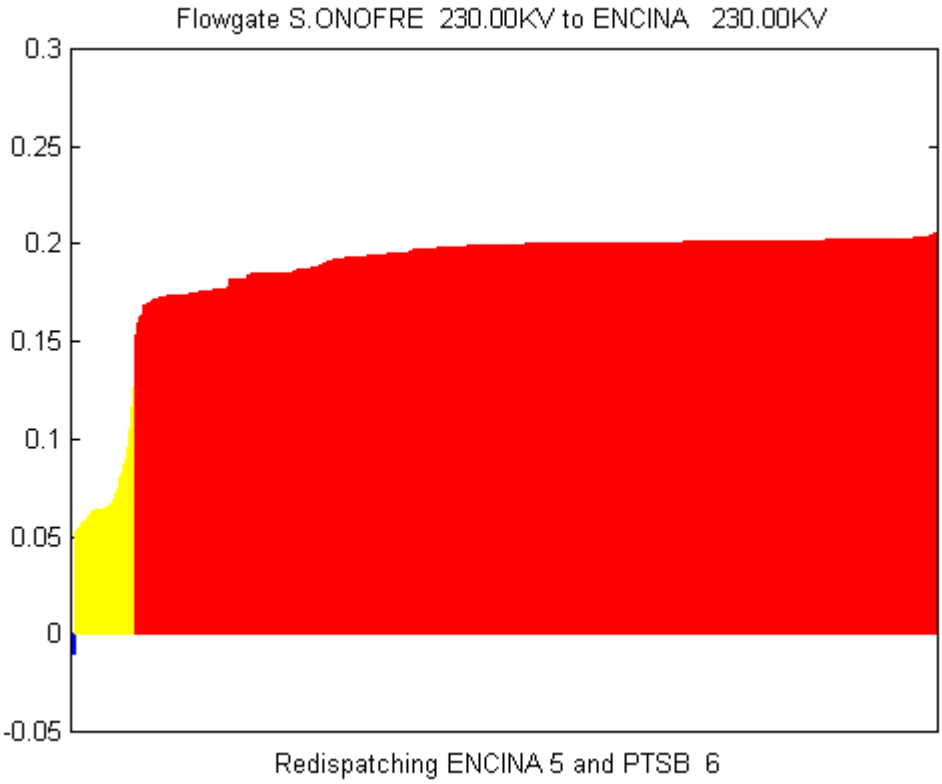

Flowgate Flowgate consisting of 3 lines
0.3
0.25
0.2
0.15
0.1
0.05
0
-0.05
0
500
1000
1500
2000
2500
3000
Redispatching DEVERS and PTSB 6

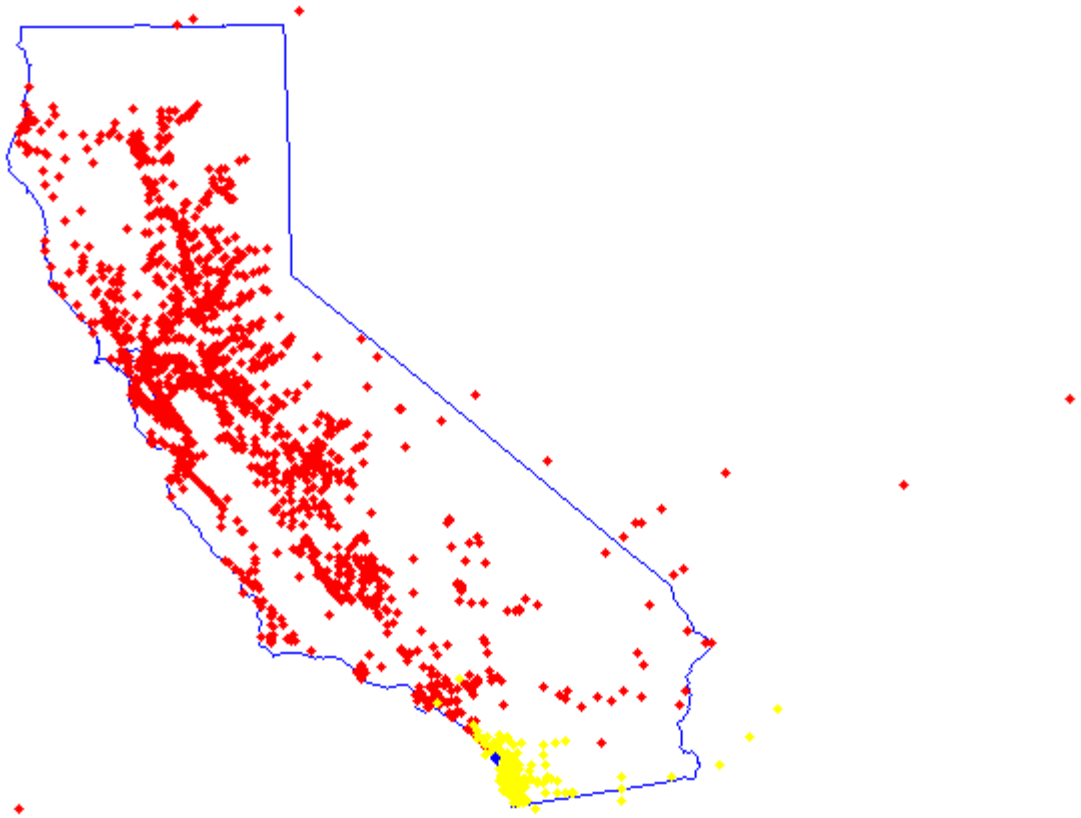


Congestion on Path 44 components

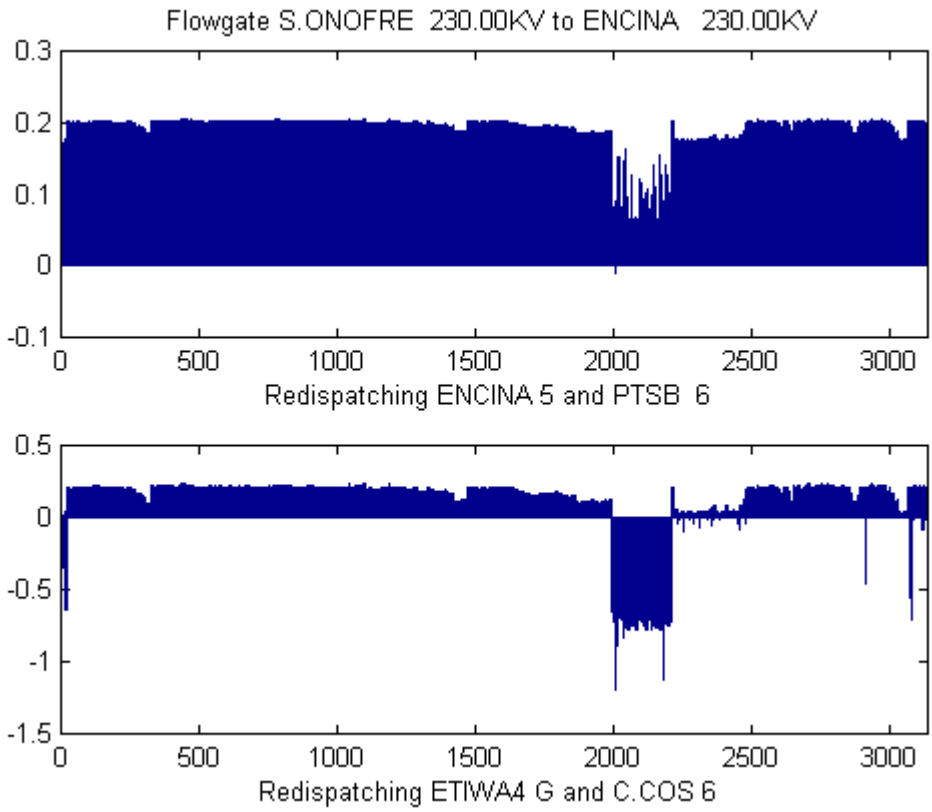


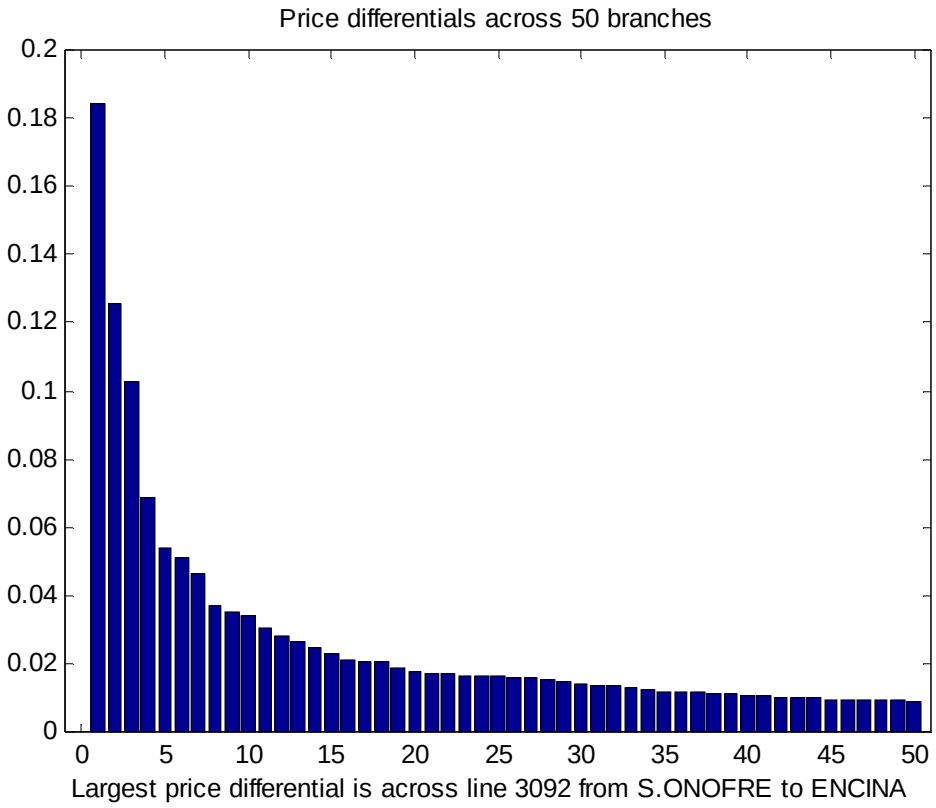

Price differentials across 50 branches
0.2
0.18
0.16
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 3092 from S.ONOFRE to ENCINA

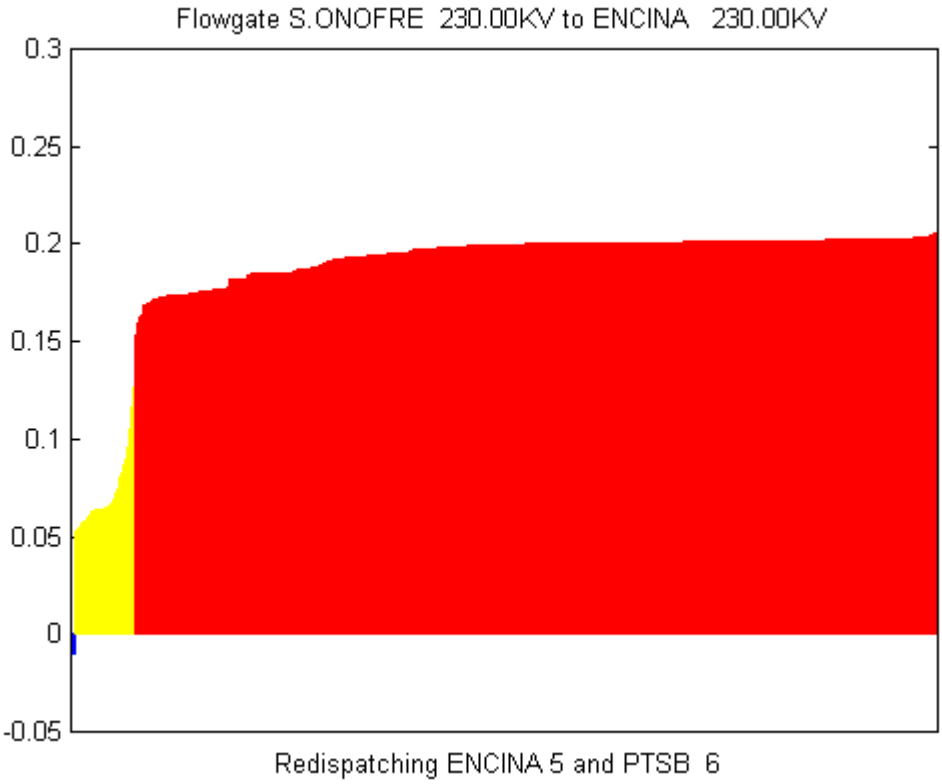

Flowgate S.ONOFRE 230.00KV to ENCINA 230.00KV
0.3
0.25
0.2
0.15
0.1
0.05
0
-0.05
Redispatching ENCINA 5 and PTSB 6

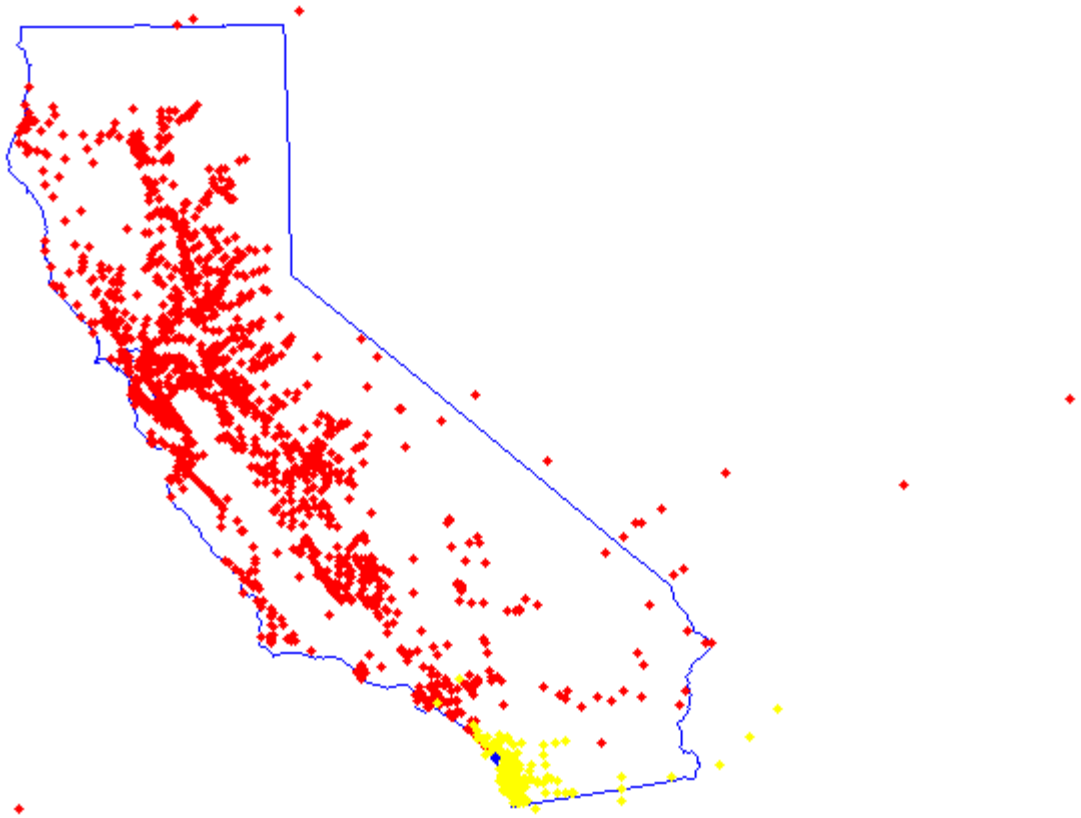


Congestion on Path 44 component

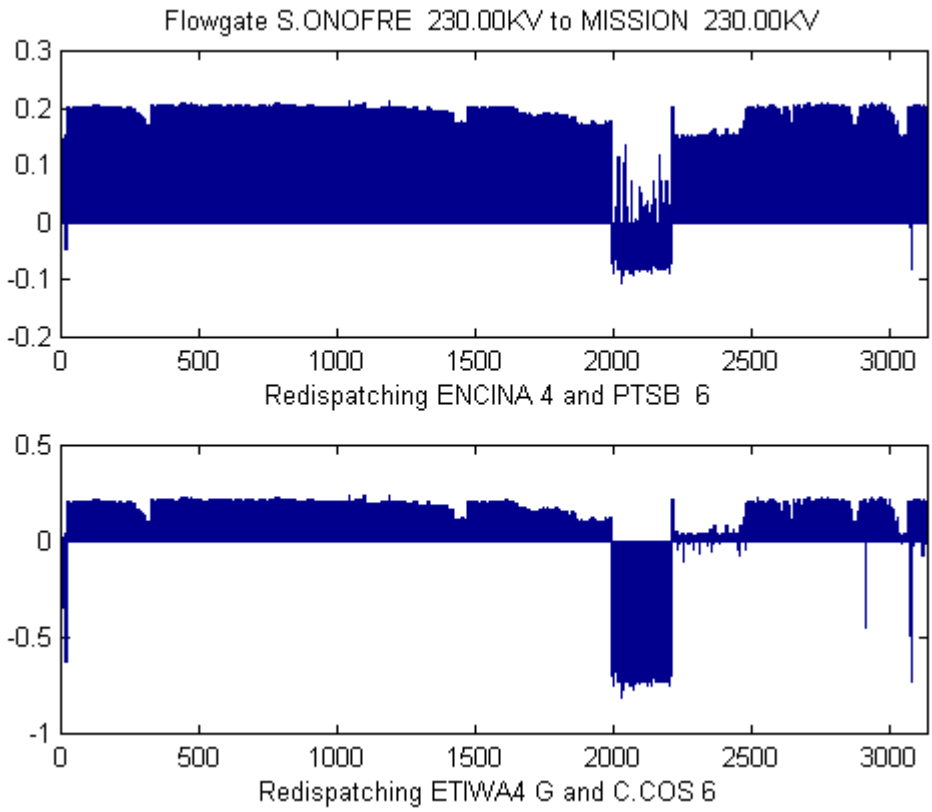


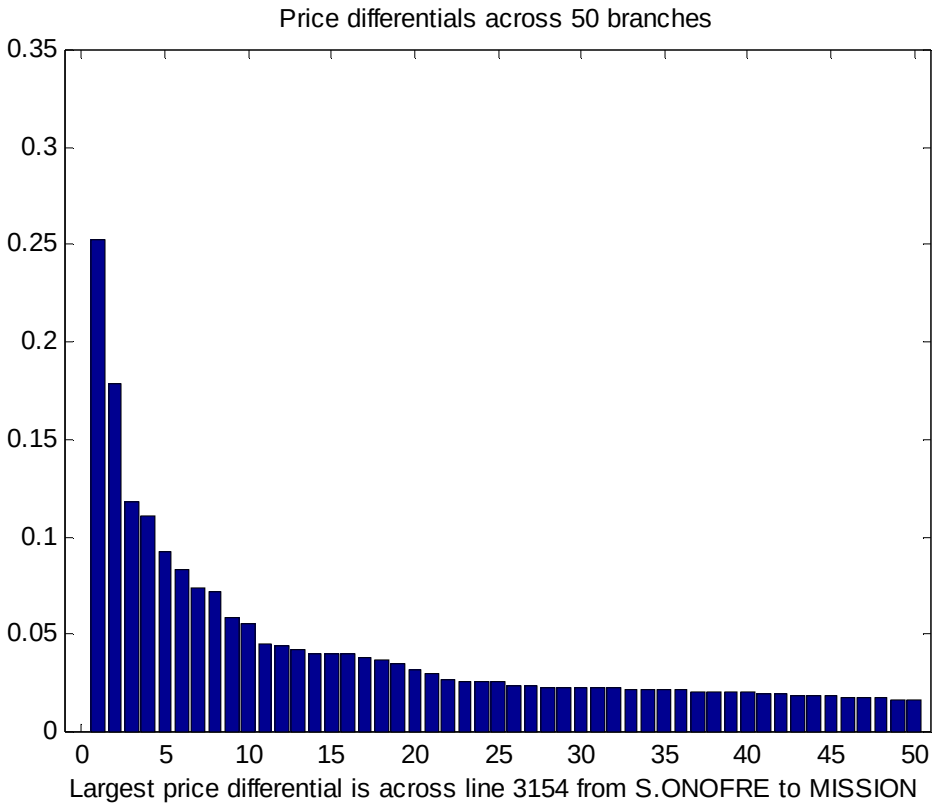

Price differentials across 50 branches
0.2
0.18
0.16
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 3092 from S.ONOFRE to ENCINA


Flowgate S.ONOFRE 230.00KV to ENCINA 230.00KV
0.3
0.25
0.2
0.15
0.1
0.05
0
-0.05
Redispatching ENCINA 5 and PTSB 6

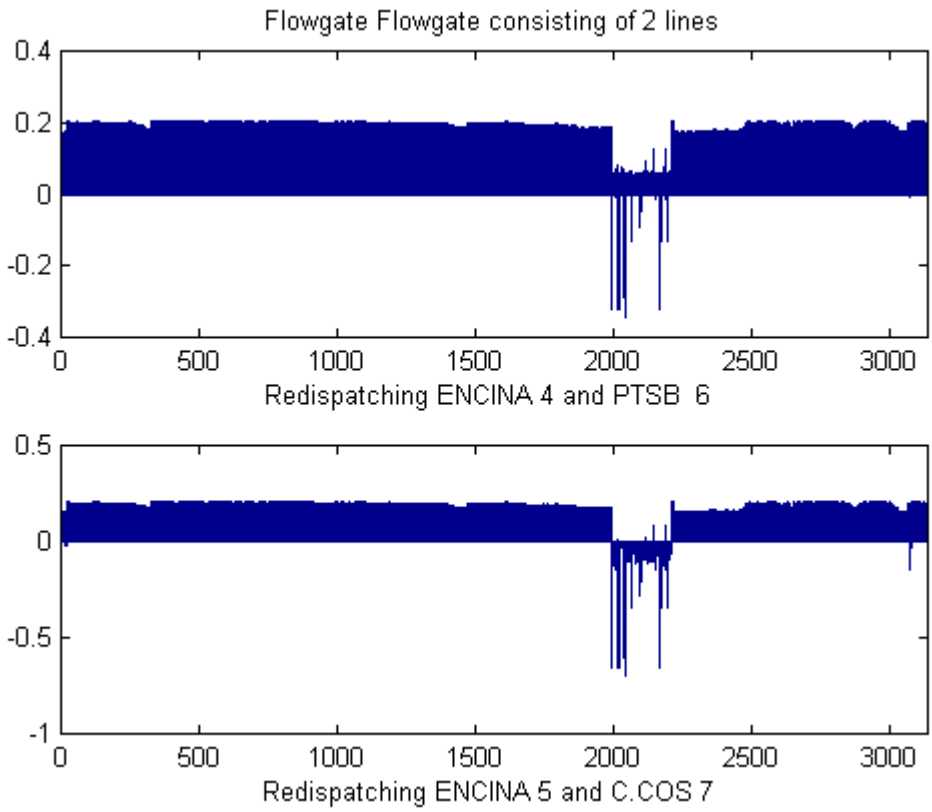


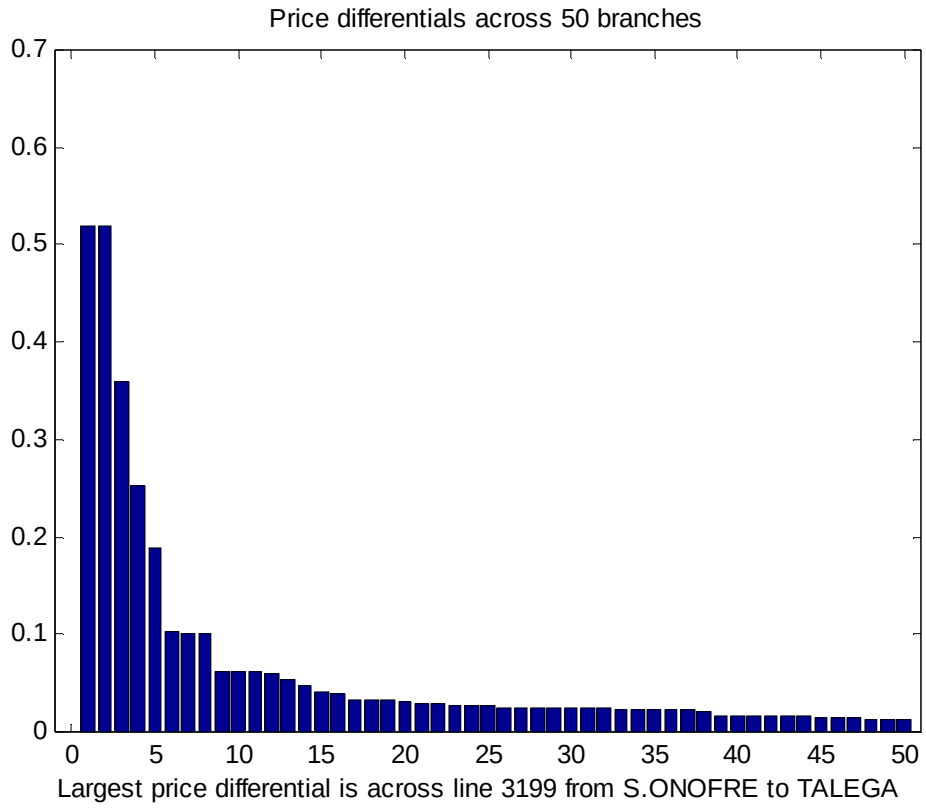
Congestion on Path 44 component

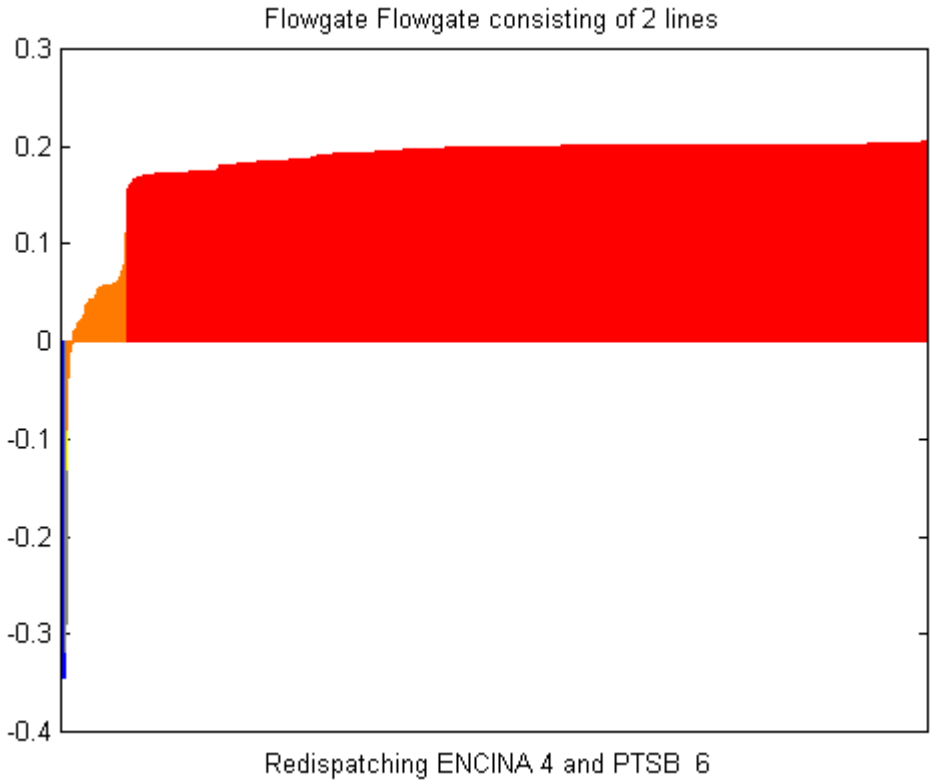


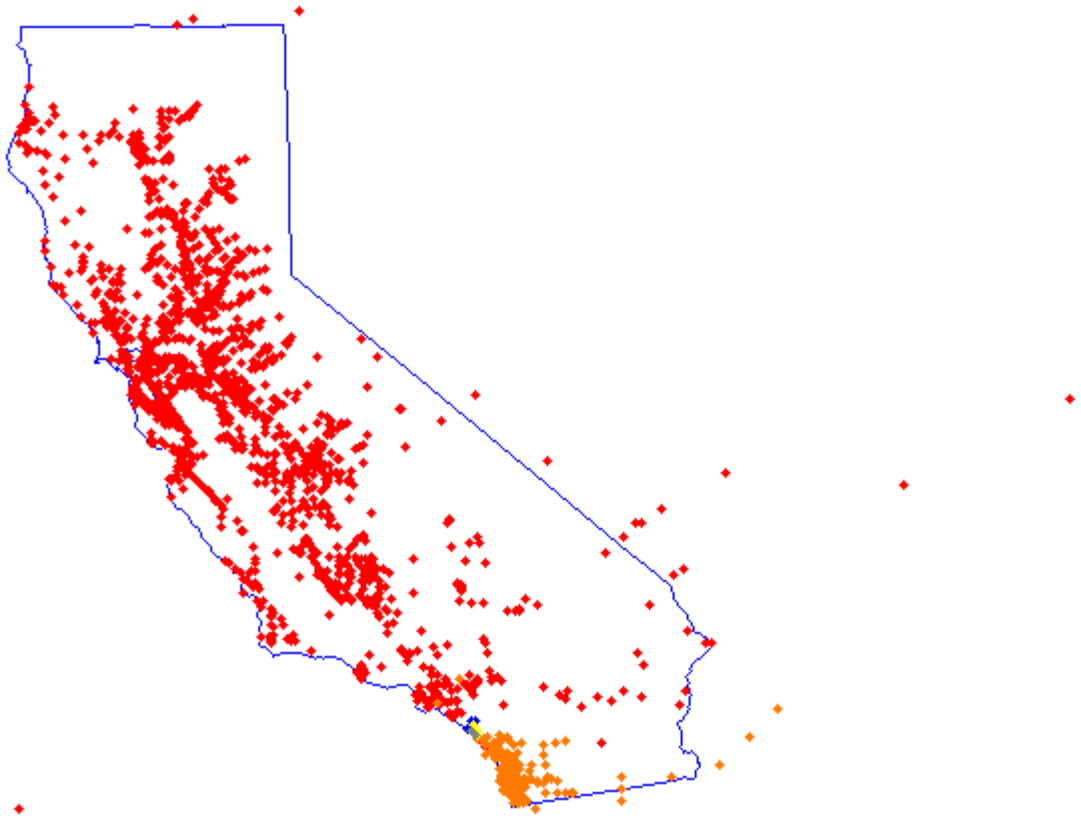

Price differentials across 50 branches
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 3154 from S.ONOFRE to MISSION

Congestion on Path 44 component

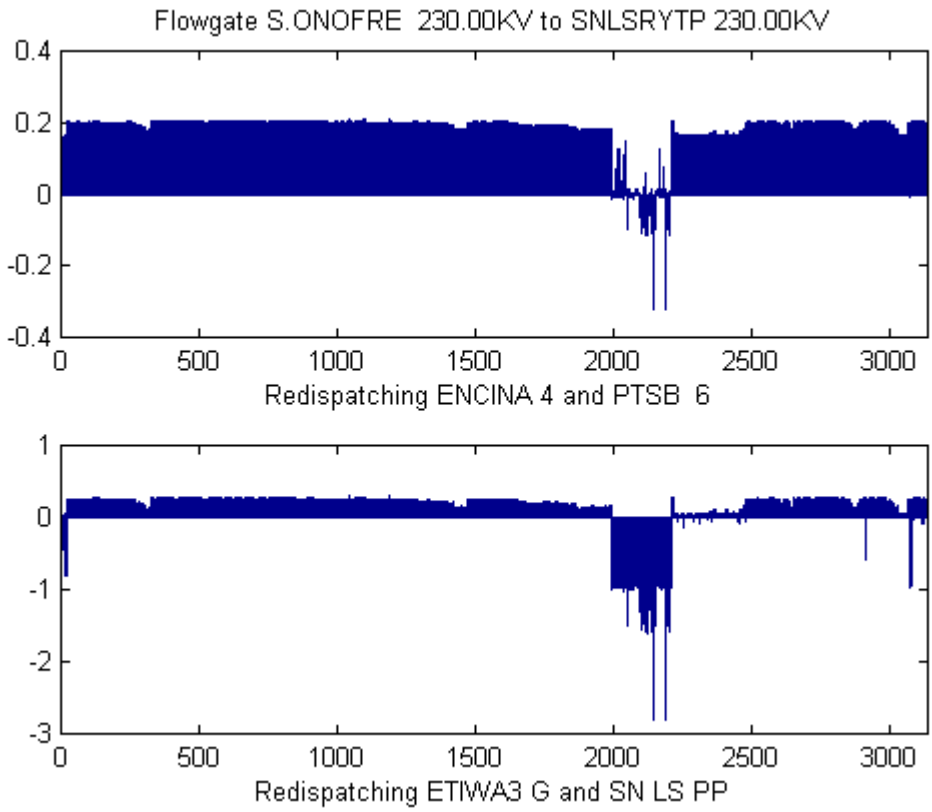


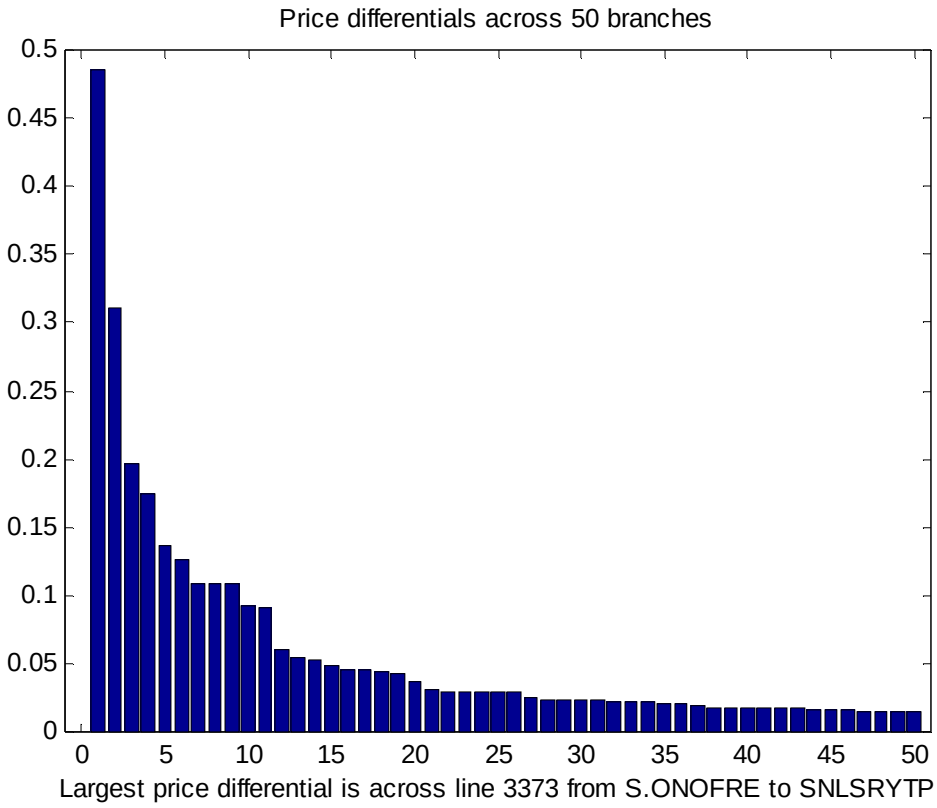

Price differentials across 50 branches
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 3199 from S.ONOFRE to TALEGA

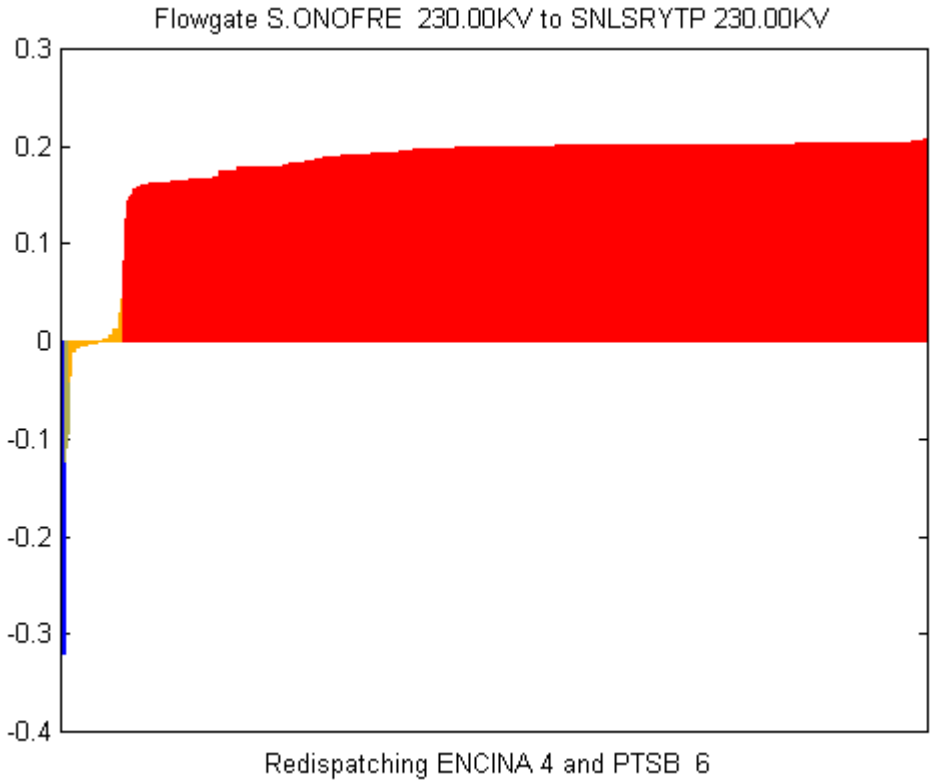

Flowgate Flowgate consisting of 2 lines
0.3
0.2
0.1
0
-0.1
-0.2
-0.3
-0.4
Redispatching ENCINA 4 and PTSB 6

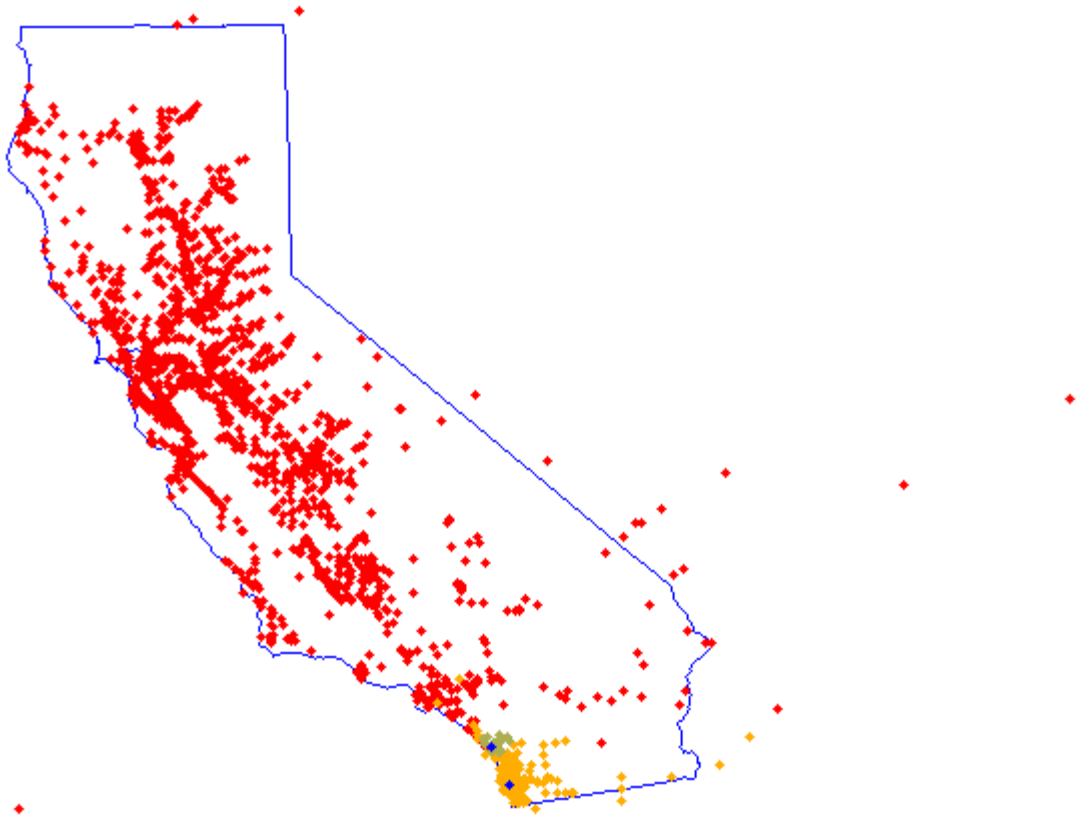


Congetion on Path 44 component

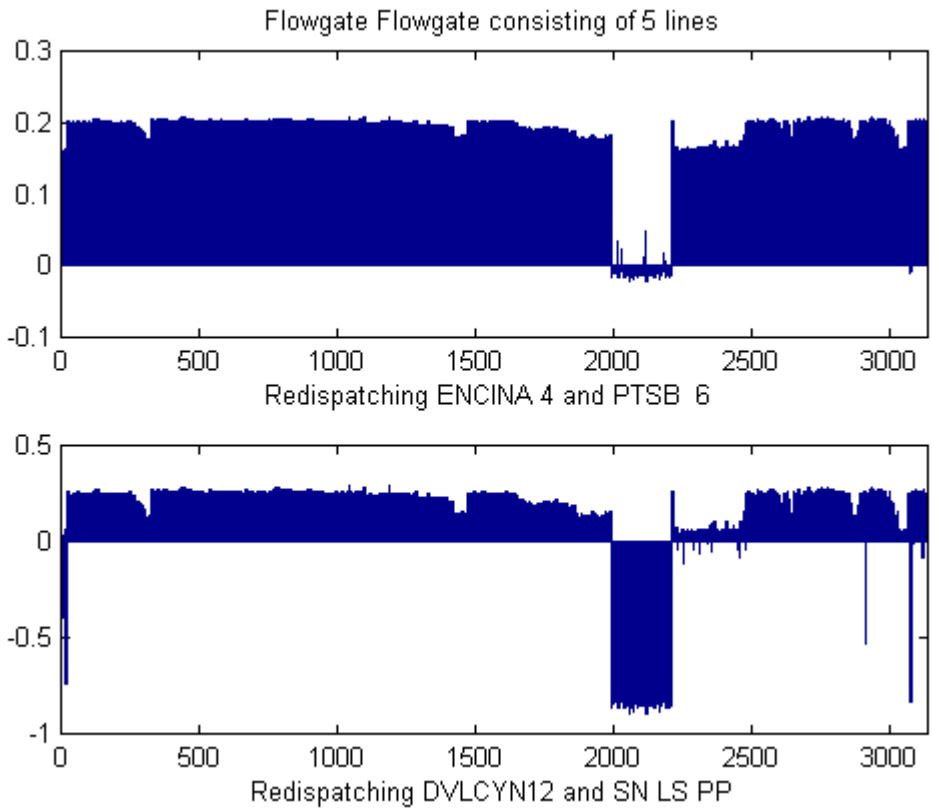


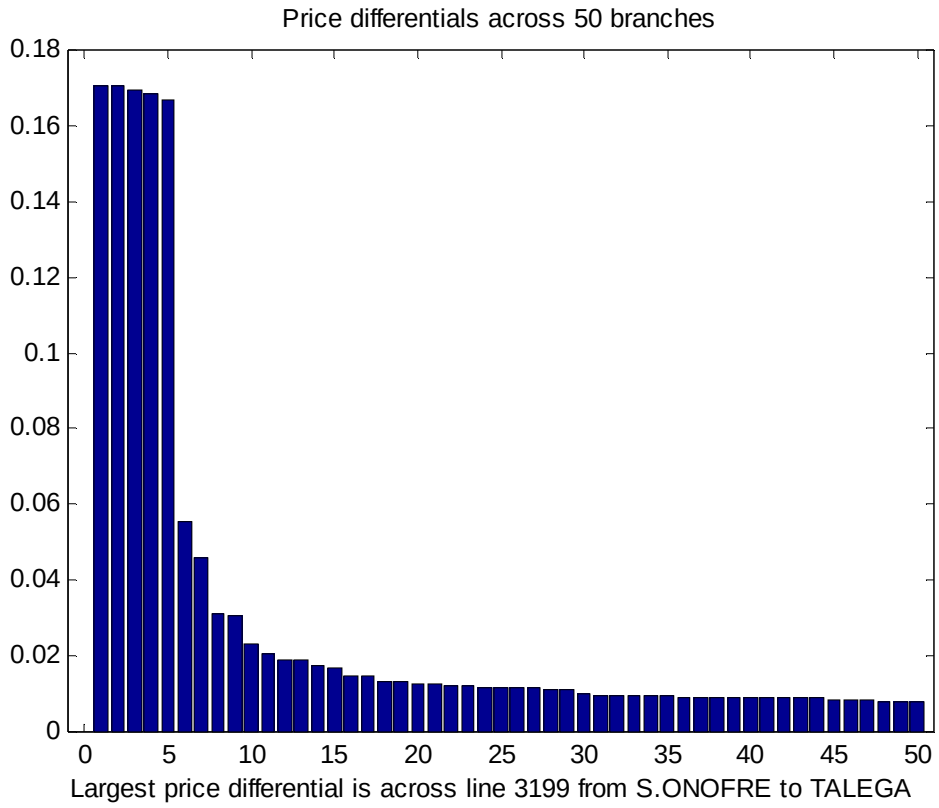

Price differentials across 50 branches
0.5
0.45
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 3373 from S.ONOFRE to SNLSRYTP

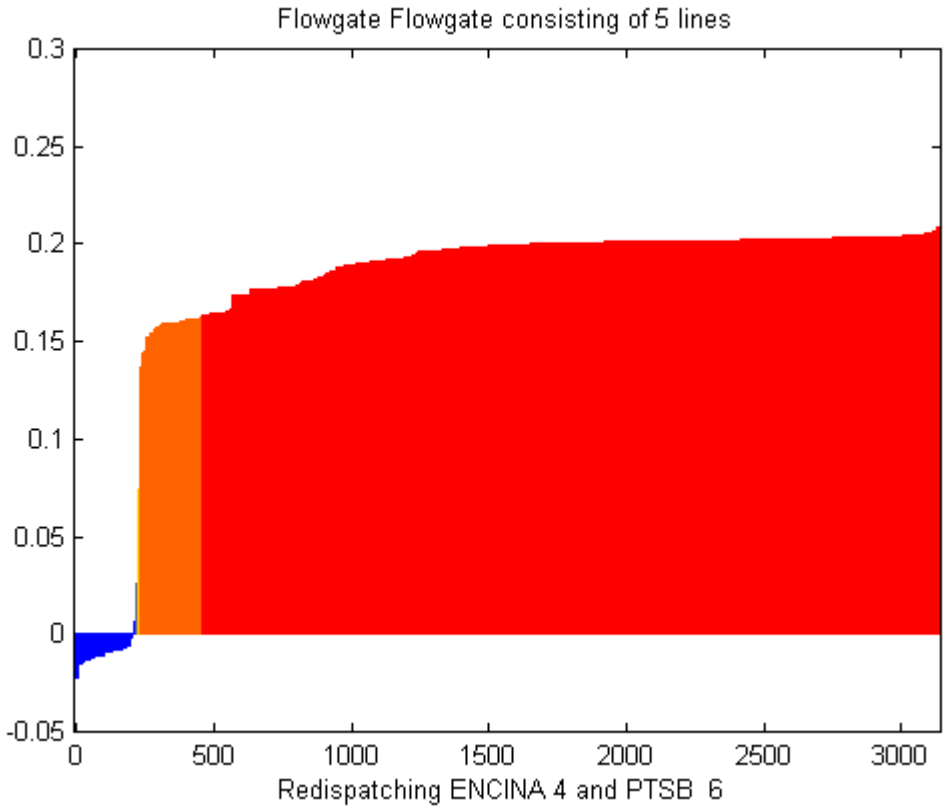

Flowgate S.ONOFRE 230.00KV to SNLSRYTP 230.00KV
0.3
0.2
0.1
0
-0.1
-0.2
-0.3
-0.4
Redispatching ENCINA 4 and PTSB 6

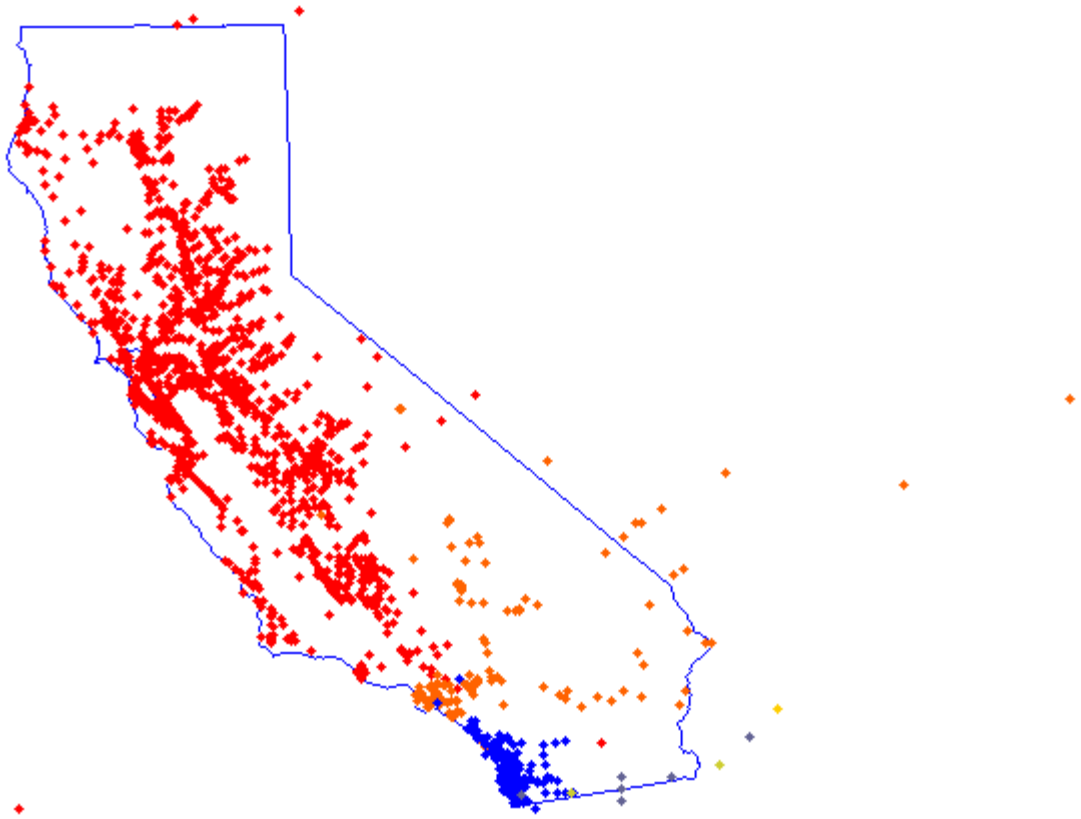


Congestion on Path 44. Congestion is on the total power across the path.

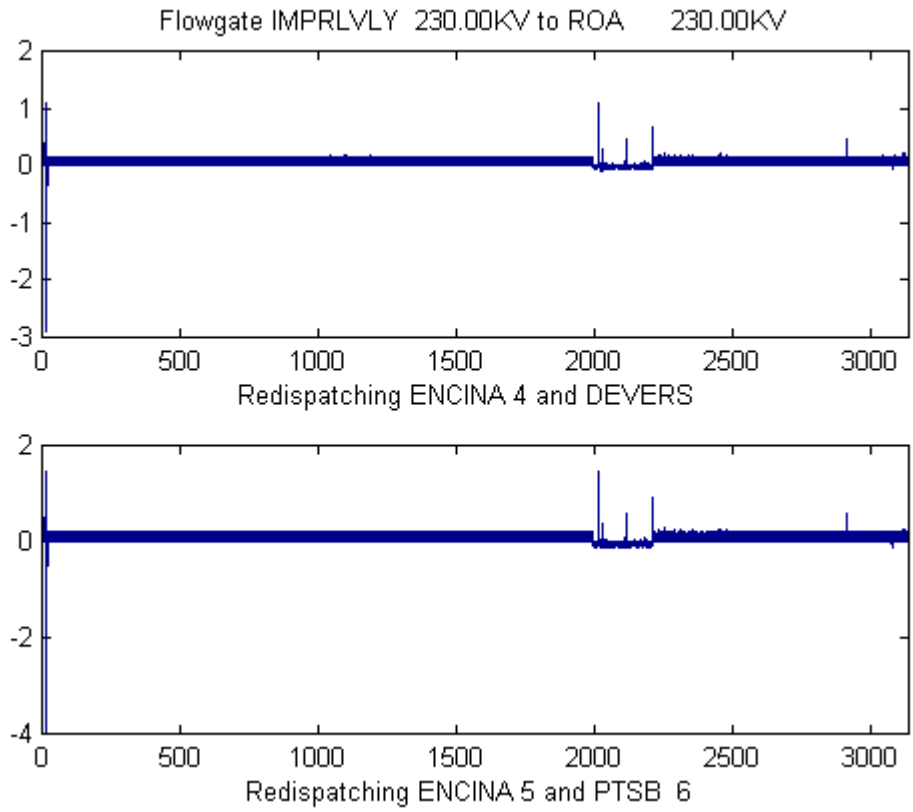


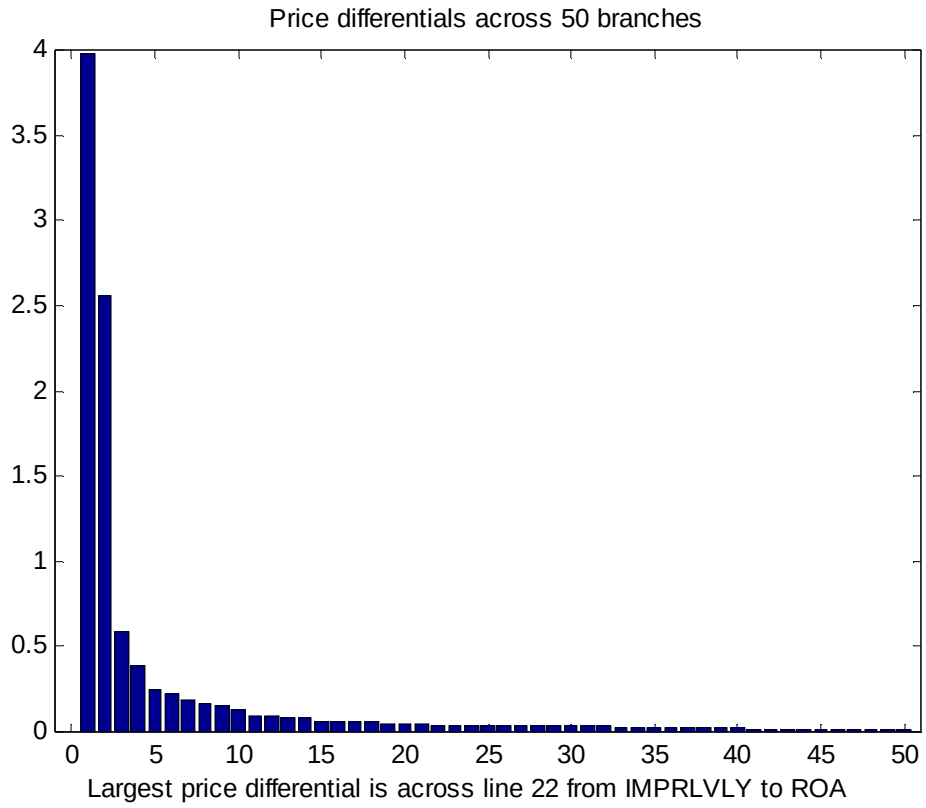

Price differentials across 50 branches
0.18
0.16
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 3199 from S.ONOFRE to TALEGA

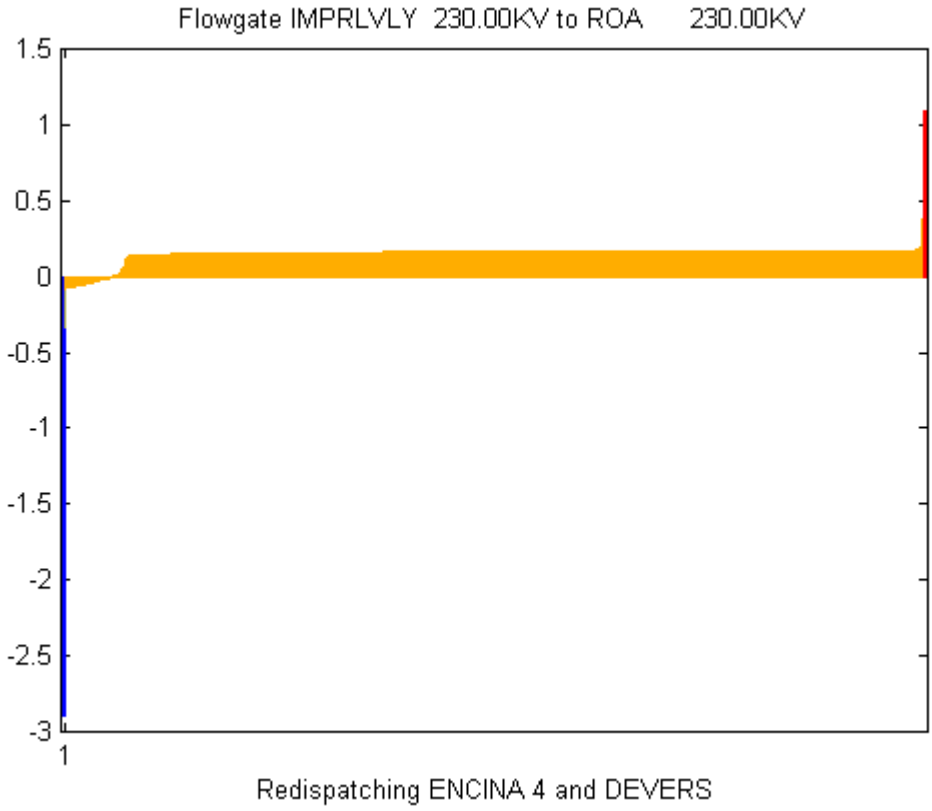

Flowgate Flowgate consisting of 5 lines
0.3
0.25
0.2
0.15
0.1
0.05
0
-0.05
0
500
1000
1500
2000
2500
3000
Redispatching ENCINA 4 and PTSB 6

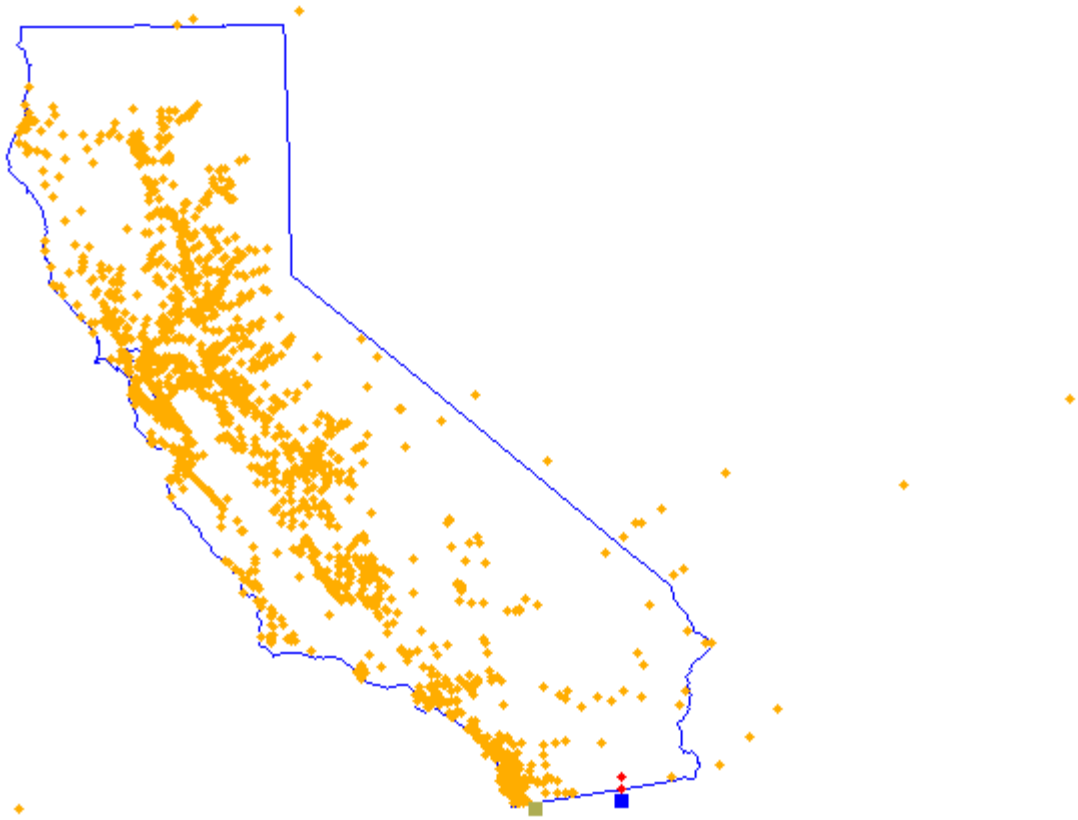


Congestion in a component of the San Diego flowgate

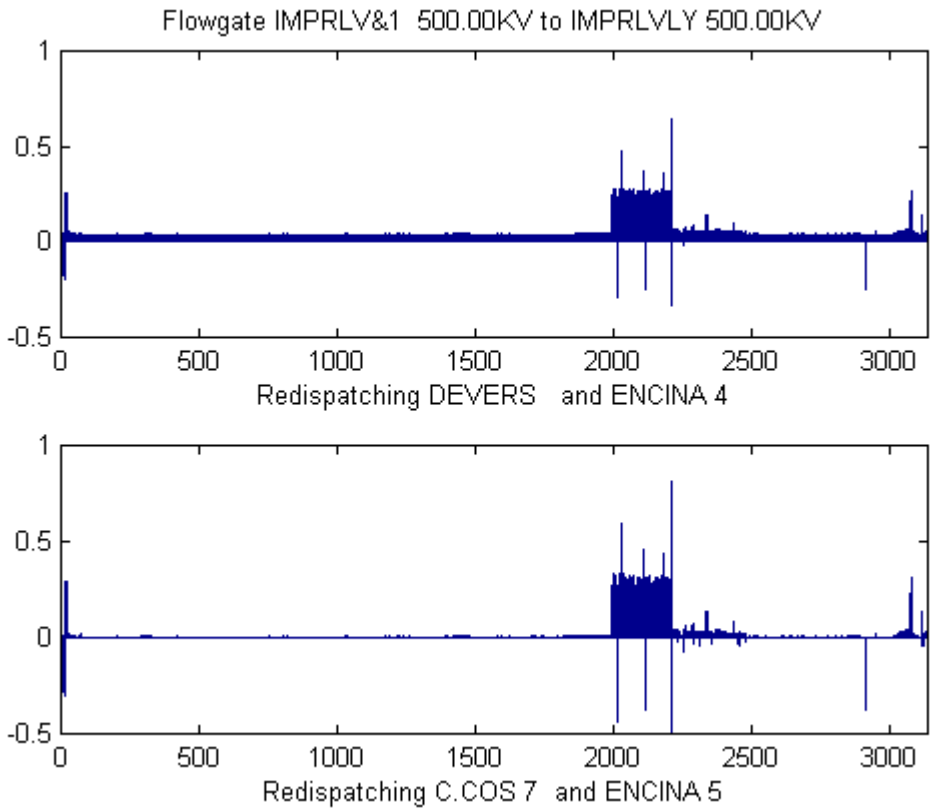


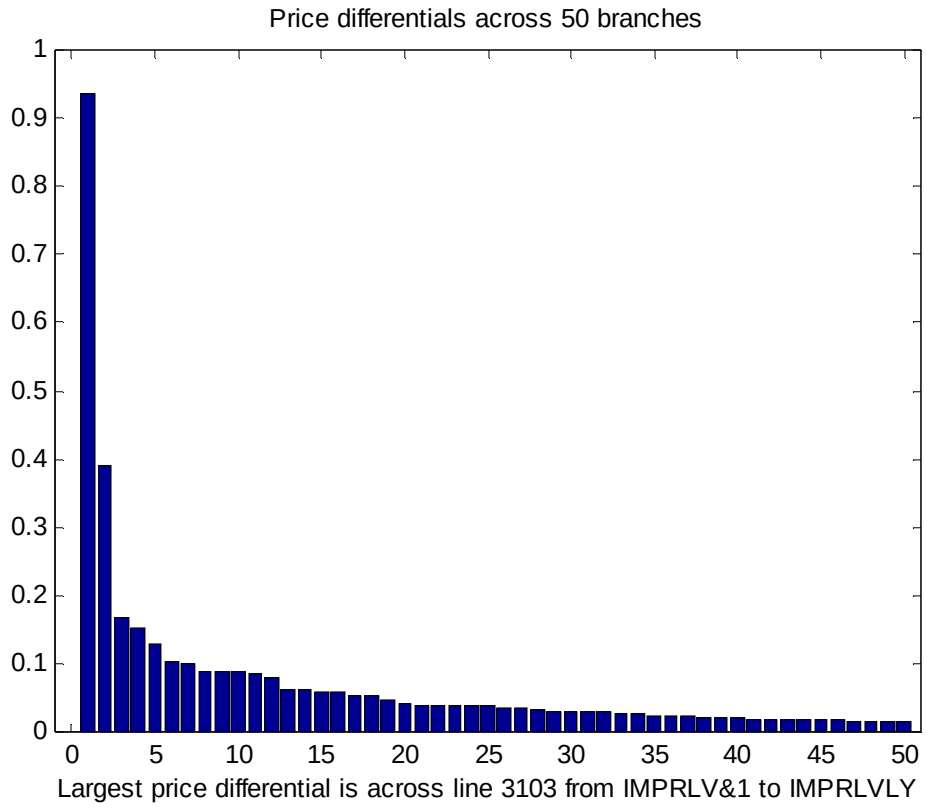

Price differentials across 50 branches
4
3.5
3
2.5
2
1.5
1
0.5
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 22 from IMPRLVLY to ROA

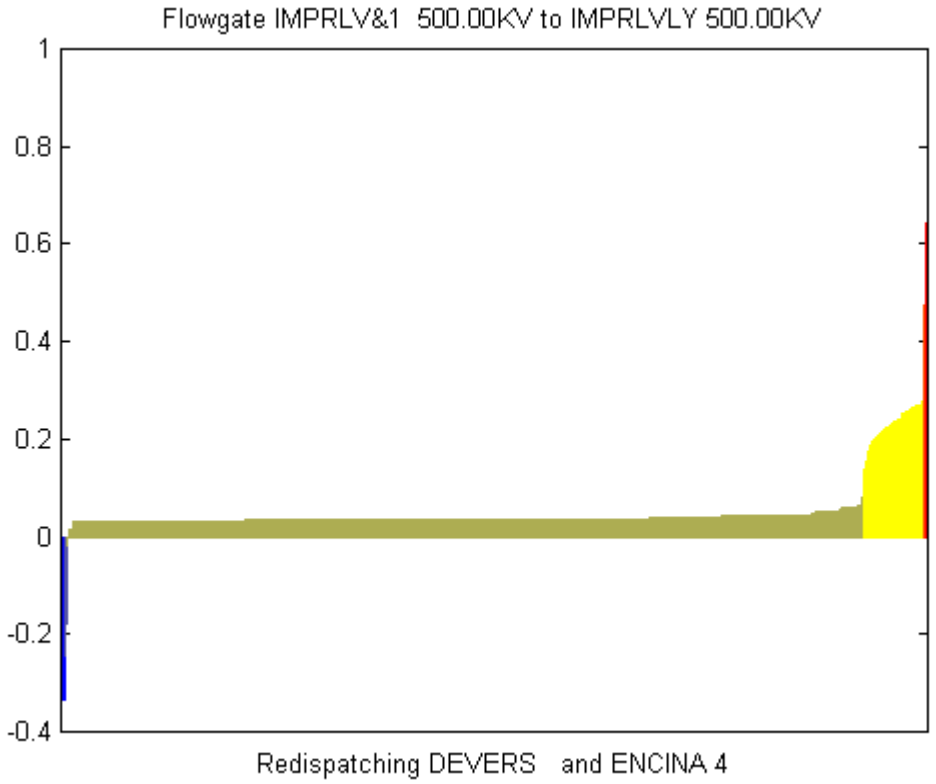

Flowgate IMPRLVLY 230.00KV to ROA 230.00KV
1.5
1
0.5
0
-0.5
-1
-1.5
-2
-2.5
-3
1
Redispatching ENCINA 4 and DEVERS

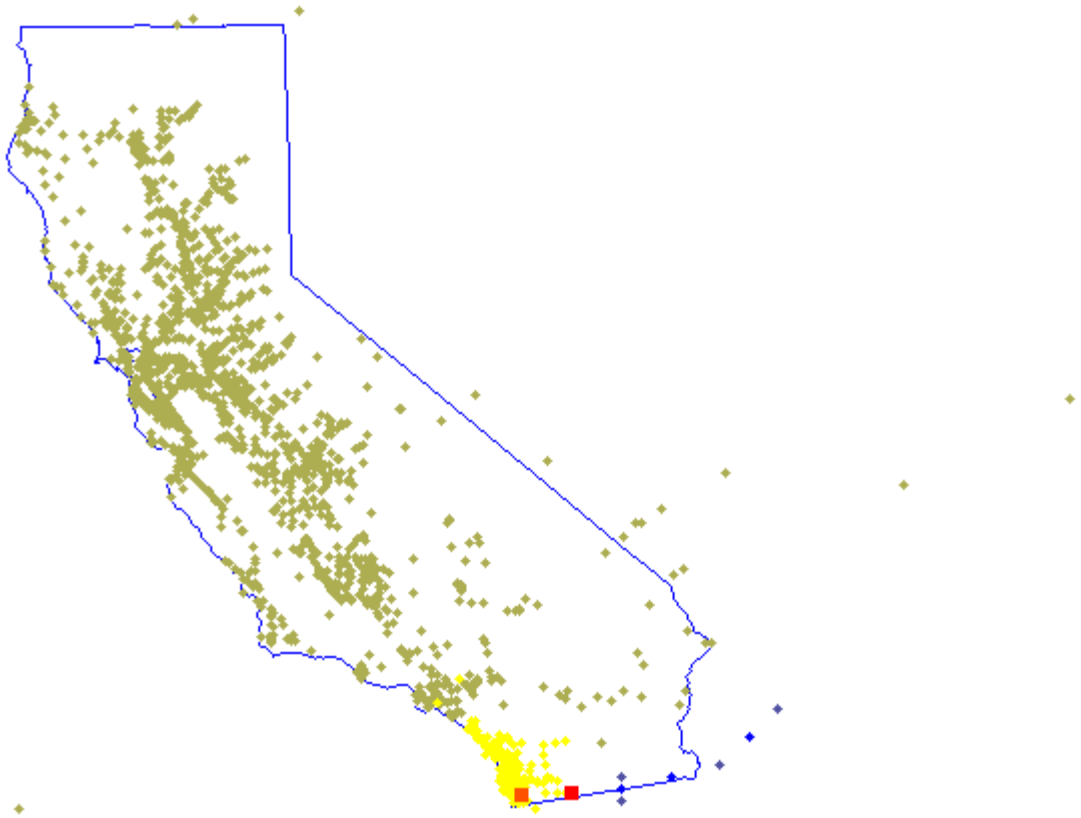


Congestion in a component of the San Diego flowgate

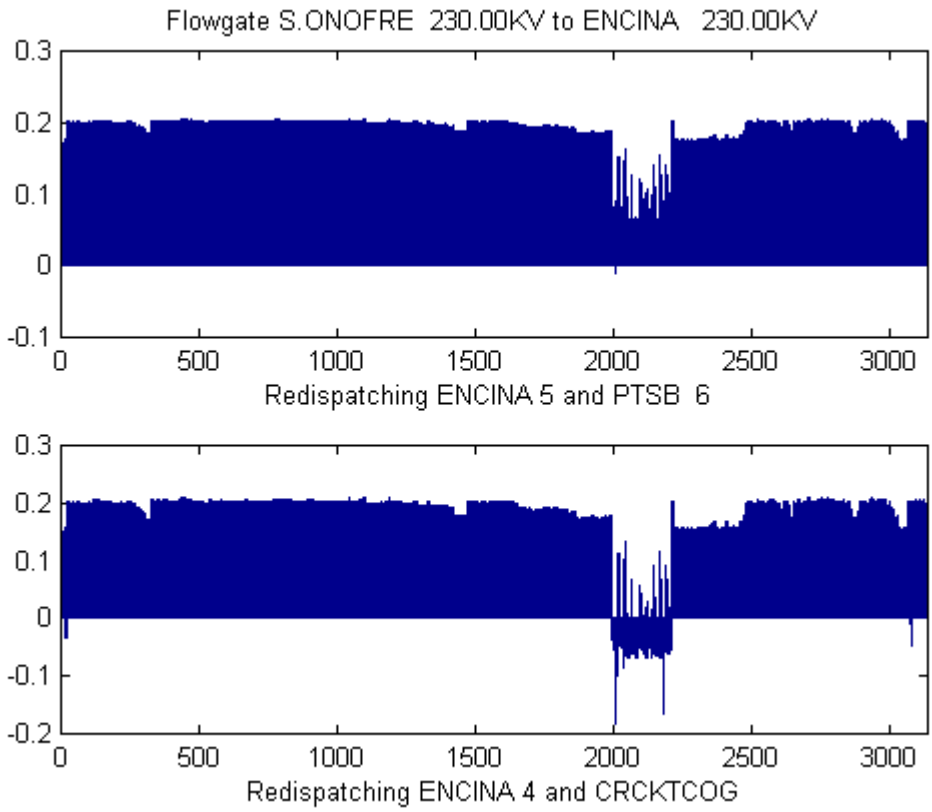


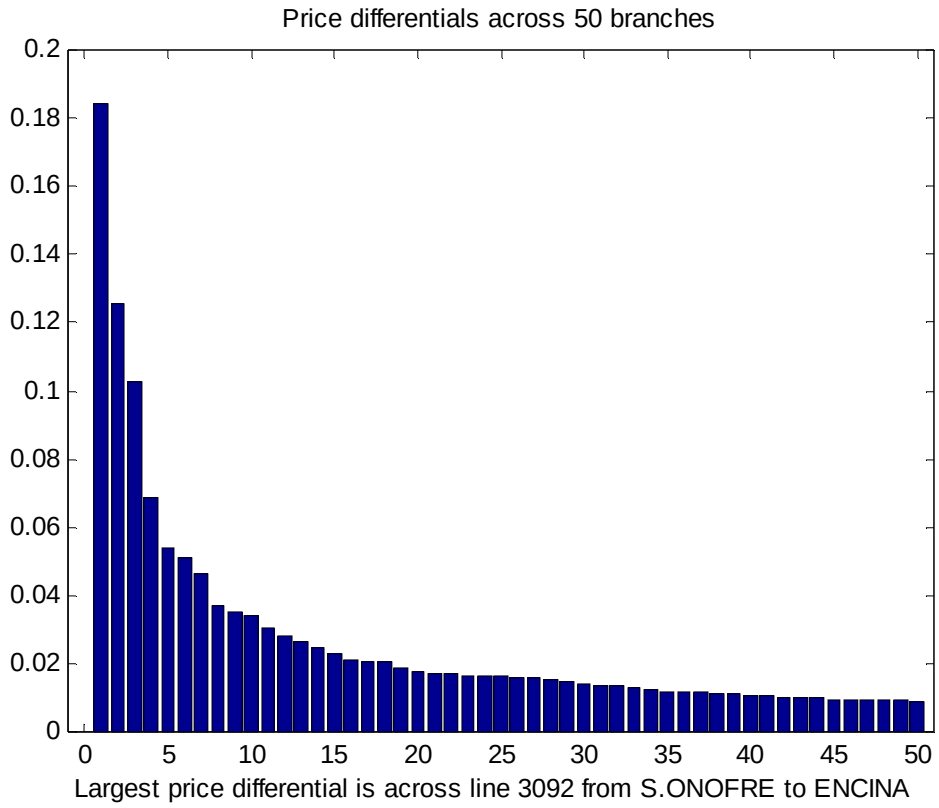

Price differentials across 50 branches
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 3103 from IMPRLV&1 to IMPRLVLY

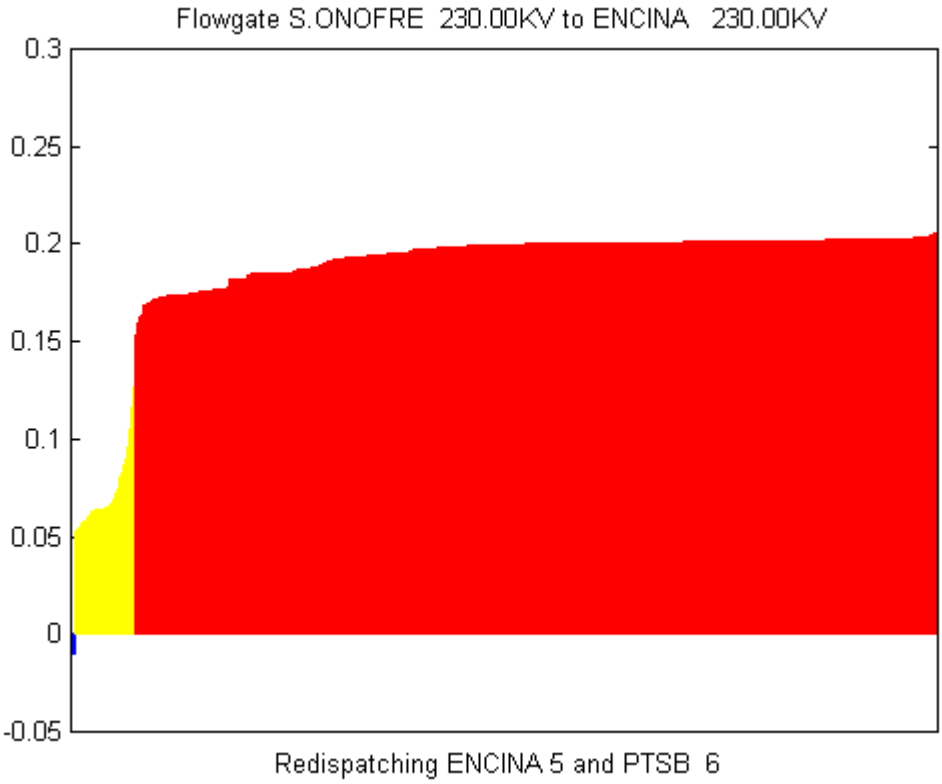

Flowgate IMPRLV&1 500.00KV to IMPRLVLY 500.00KV
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
Redispatching DEVERS and ENCINA 4

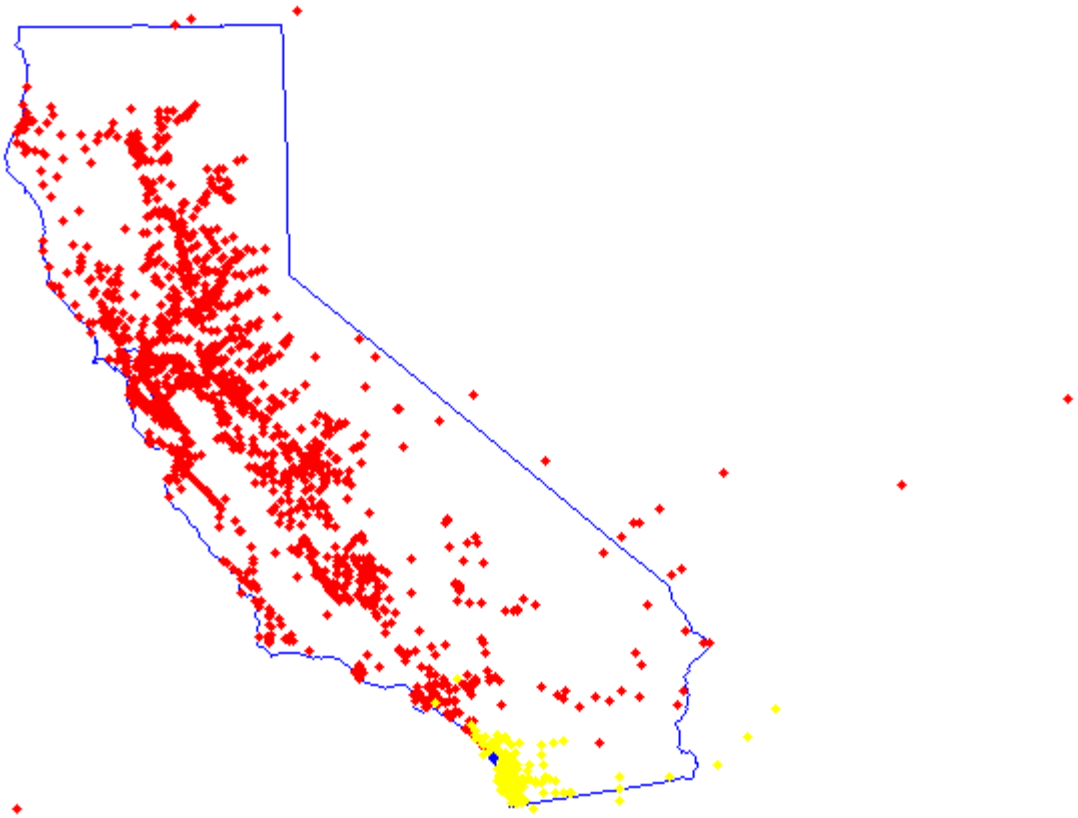


Congestion on a component of the San Diego flowgate

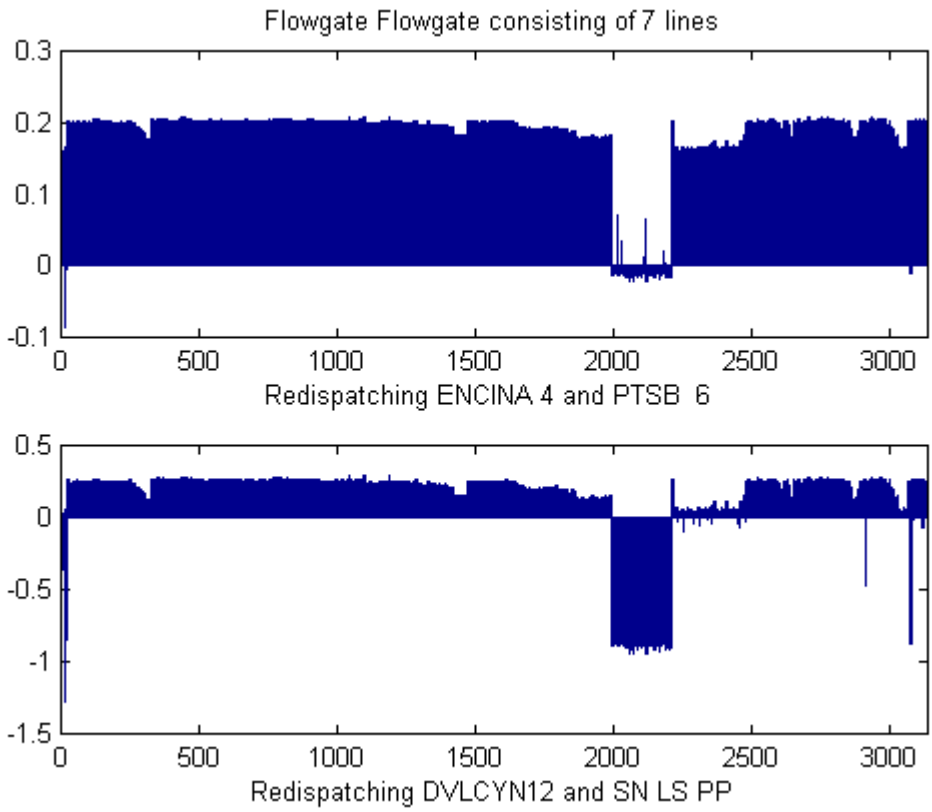


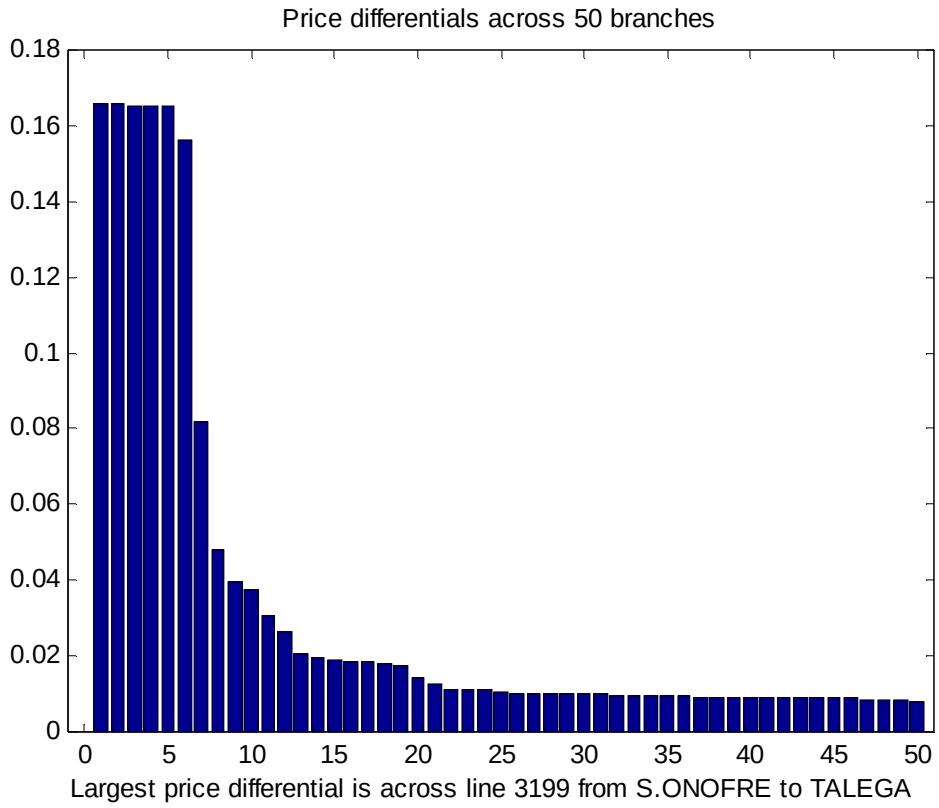

Price differentials across 50 branches
0.2
0.18
0.16
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 3092 from S.ONOFRE to ENCINA

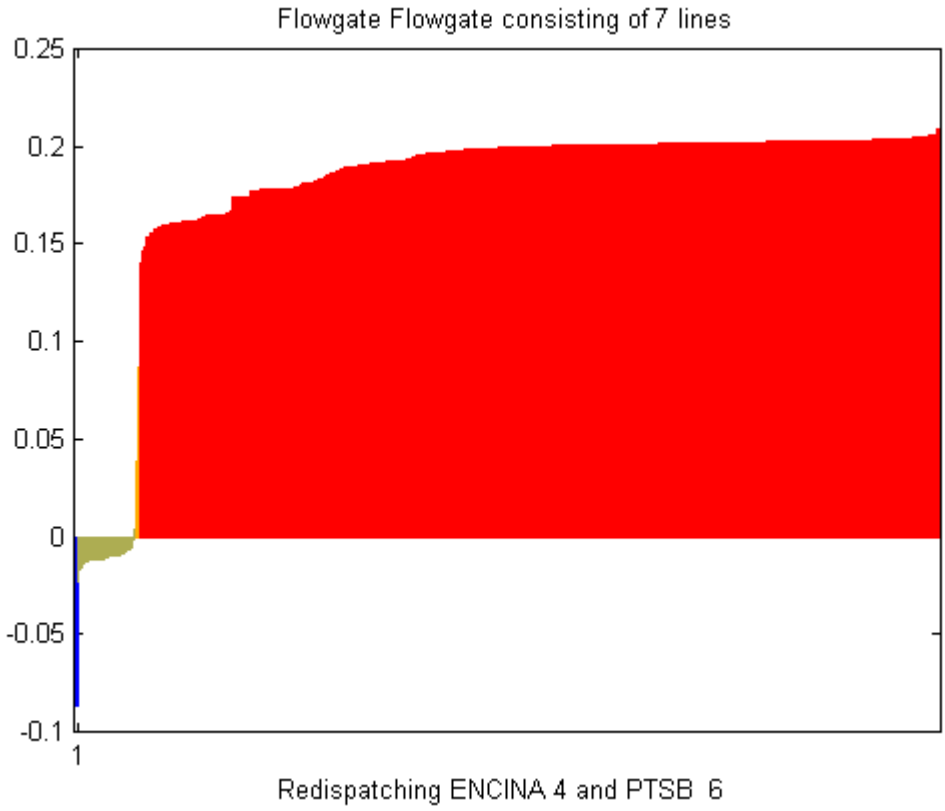

Flowgate S.ONOFRE 230.00KV to ENCINA 230.00KV
0.3
0.25
0.2
0.15
0.1
0.05
0
-0.05
Redispatching ENCINA 5 and PTSB 6

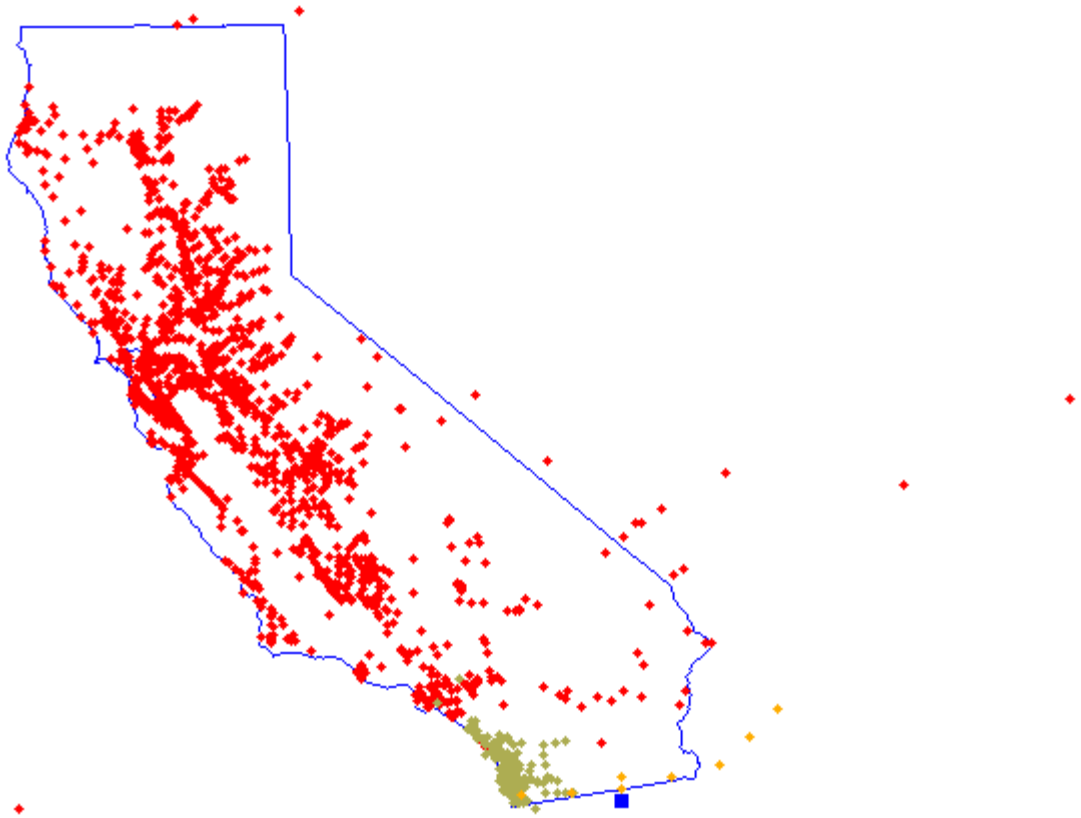


Congestion on the San Diego flowgate. Constraing is on total flowgate power.

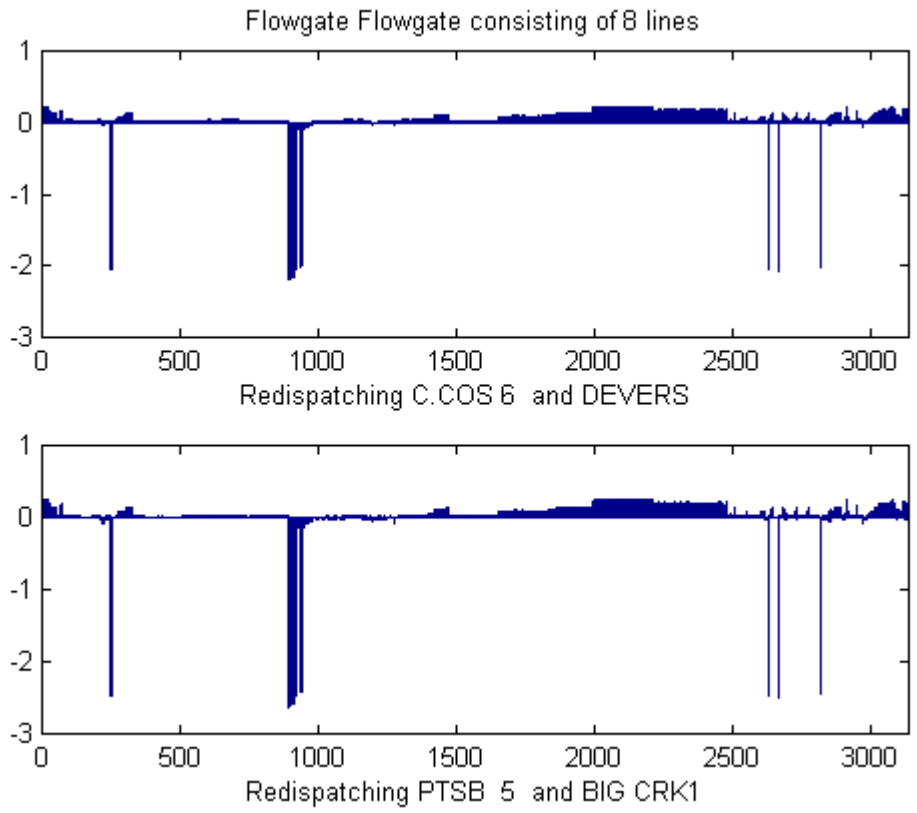


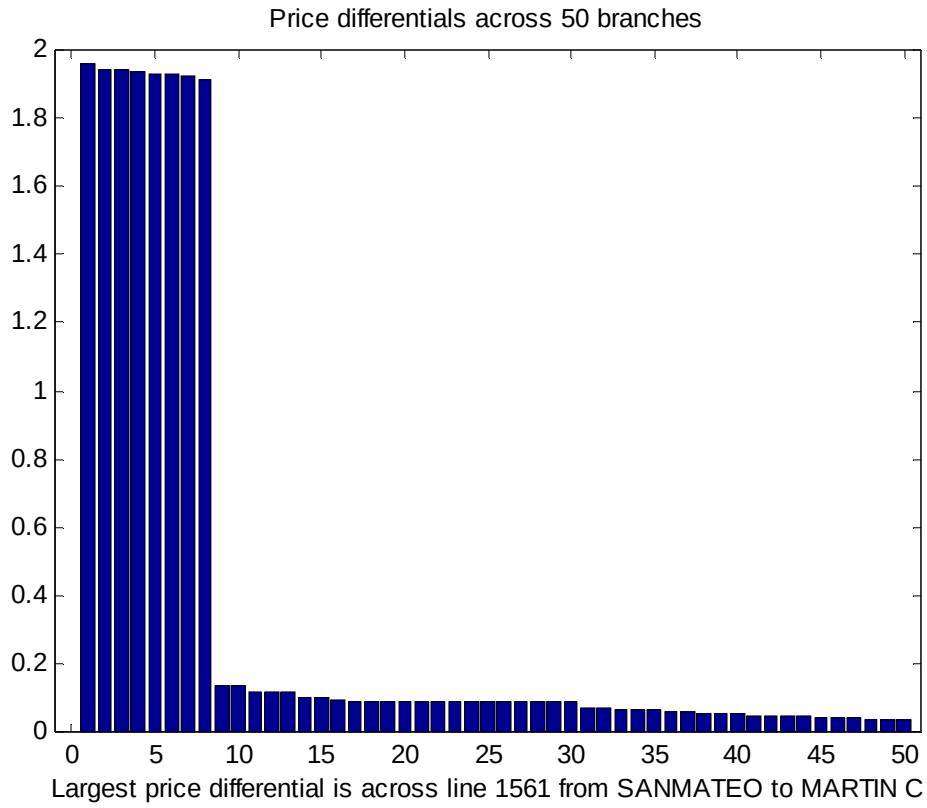

Price differentials across 50 branches
0.18
0.16
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 3199 from S.ONOFRE to TALEGA

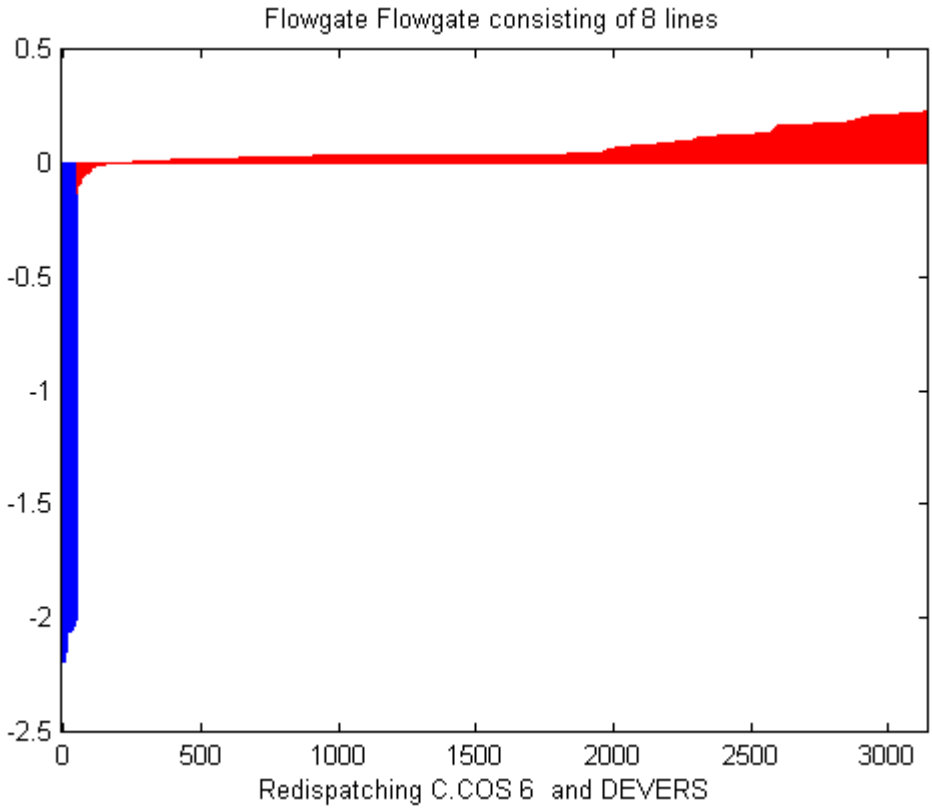

Flowgate Flowgate consisting of 7 lines
0.25
0.2
0.15
0.1
0.05
0
-0.05
-0.1
1
Redispatching ENCINA 4 and PTSB 6

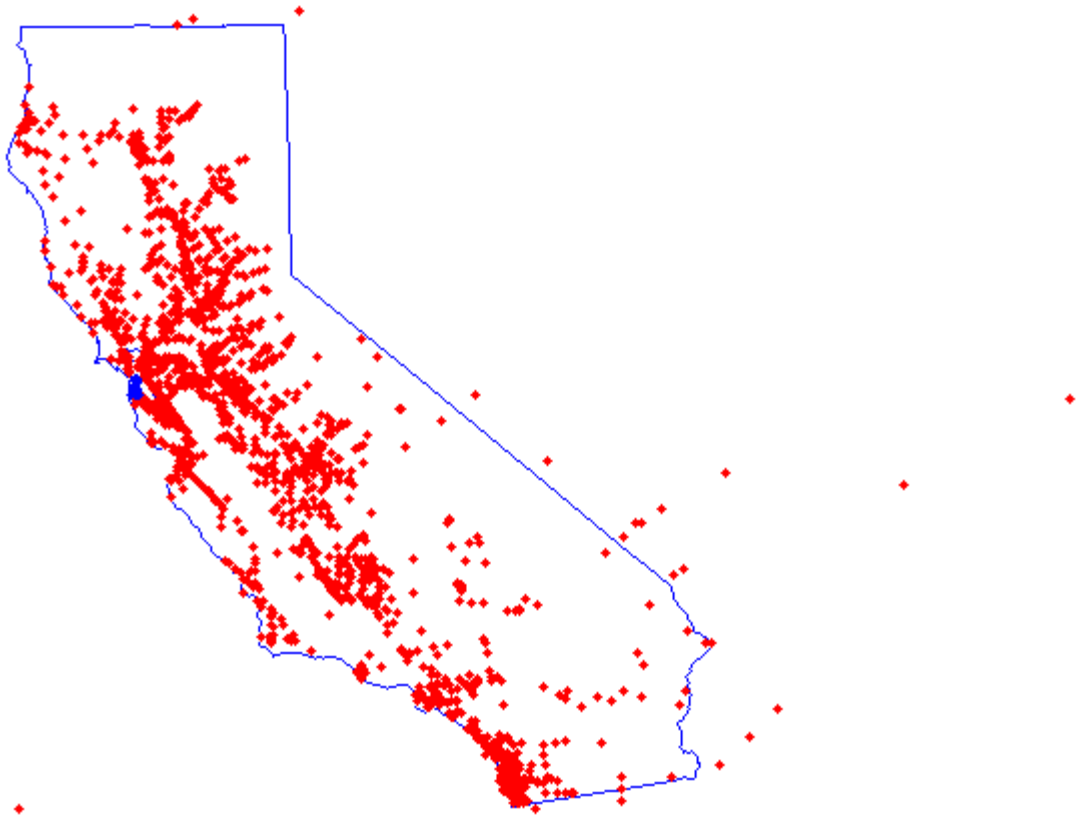


Congestion on the sum of all powers into San Francisco (San Francisco flowgate)

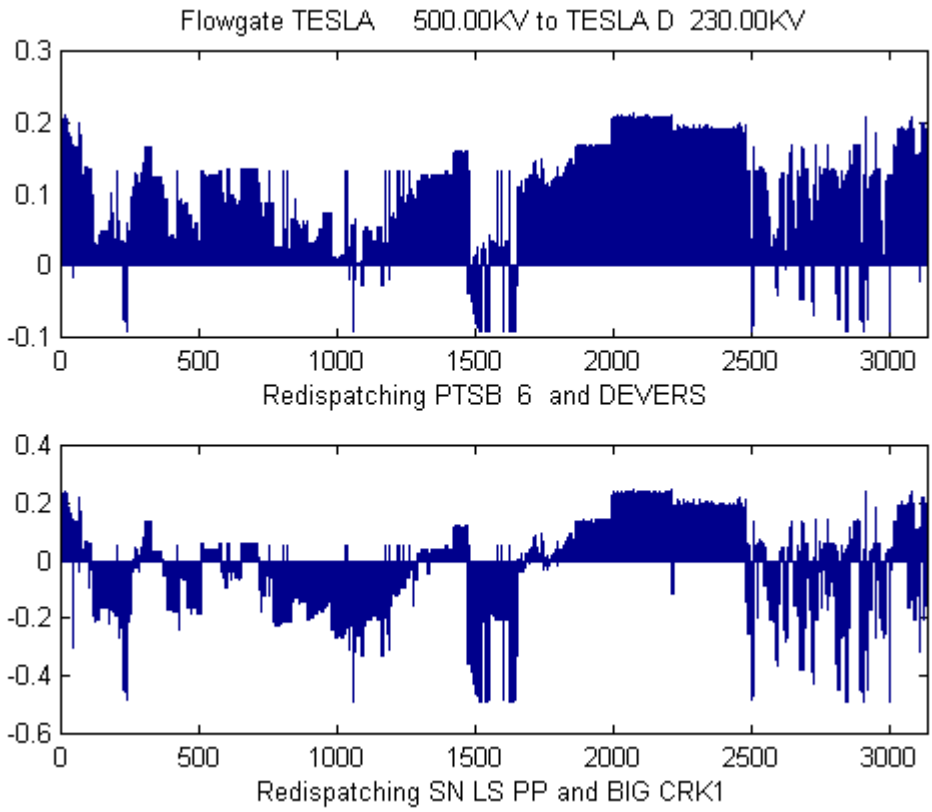


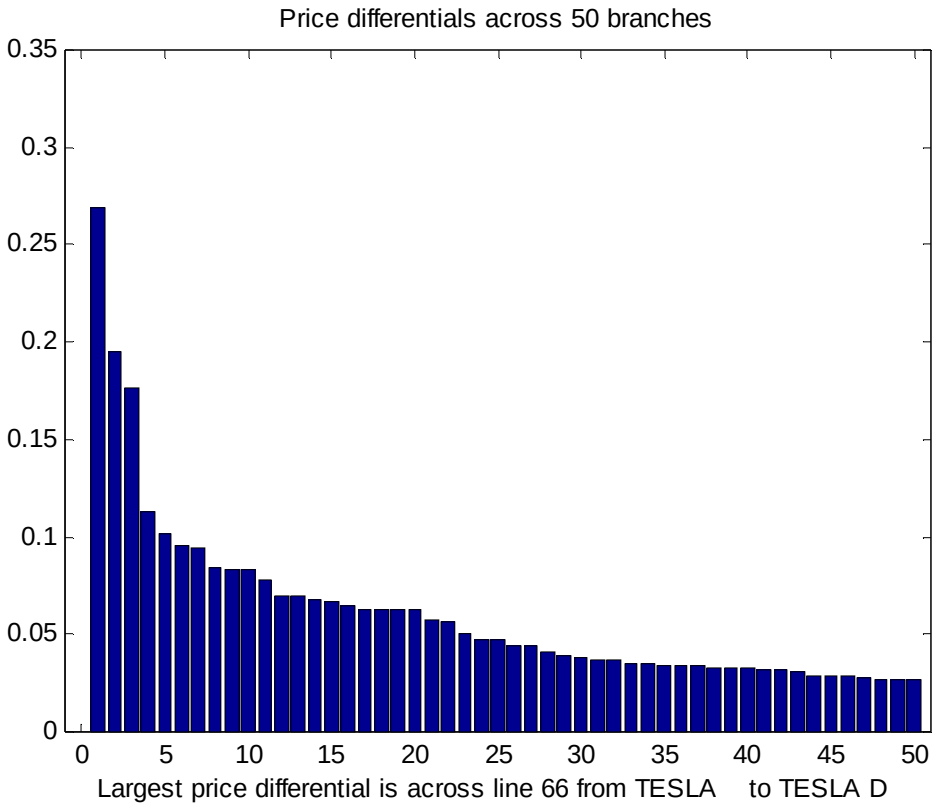

Price differentials across 50 branches
2
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 1561 from SANMATEO to MARTIN C

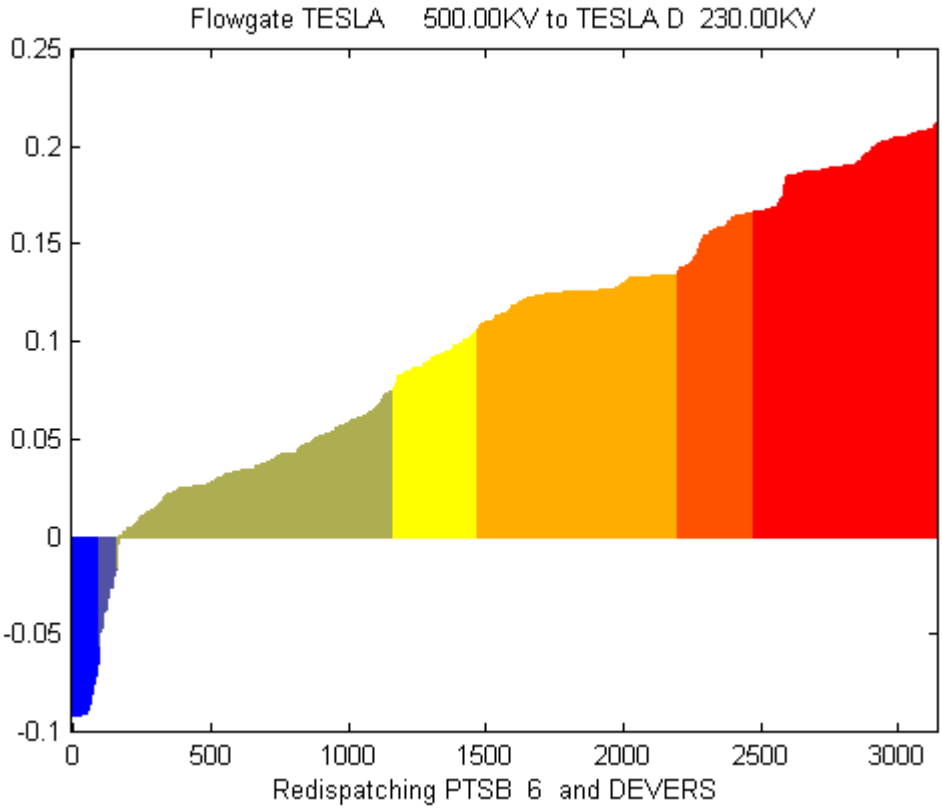

Flowgate Flowgate consisting of 8 lines
0.5
0
-0.5
-1
-1.5
-2
-2.5
0
500
1000
1500
2000
2500
3000
Redispatching C.COS 6 and DEVERS

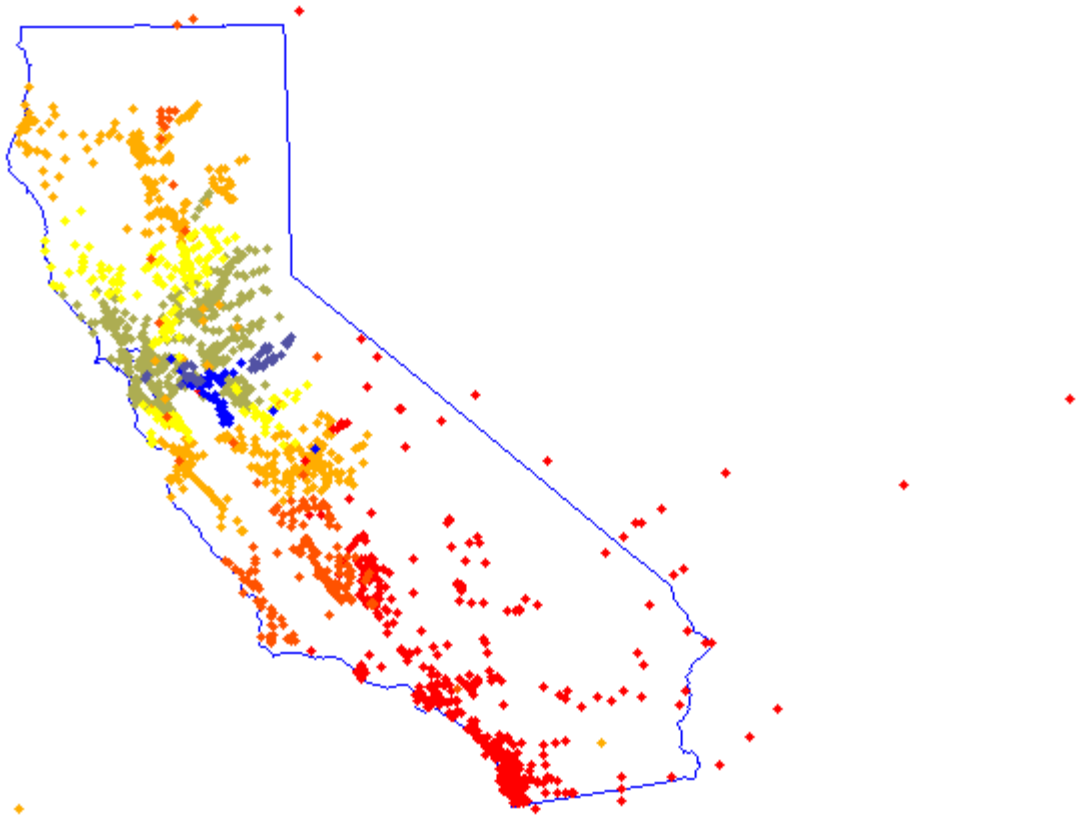


Intra-zonal congestion

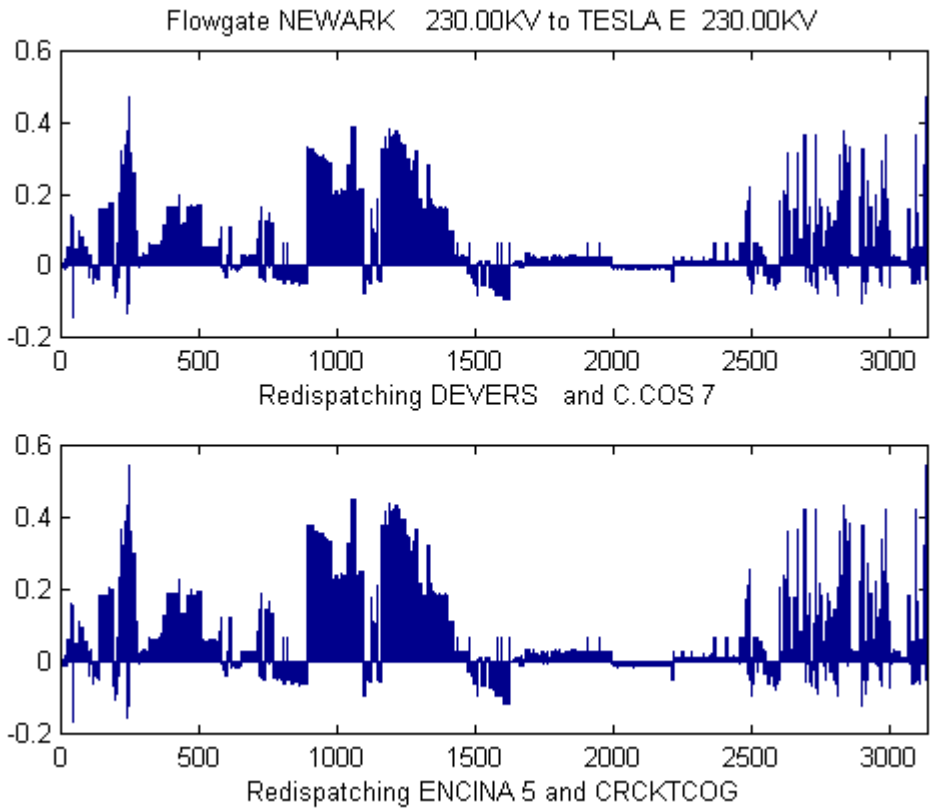


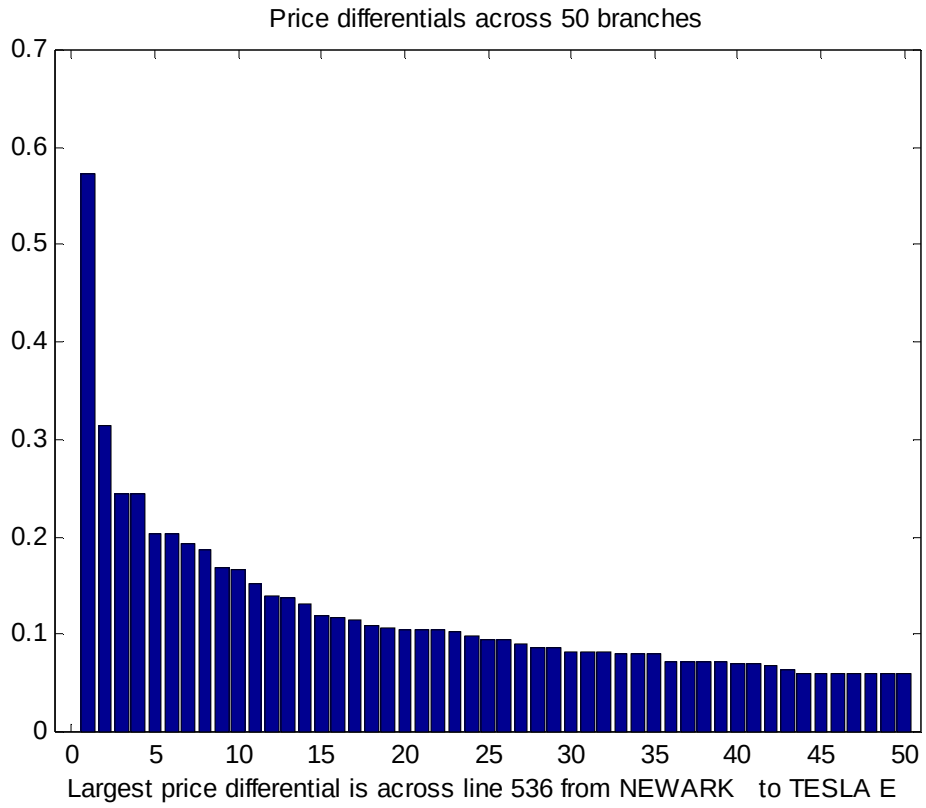

Price differentials across 50 branches
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 66 from TESLA to TESLA D

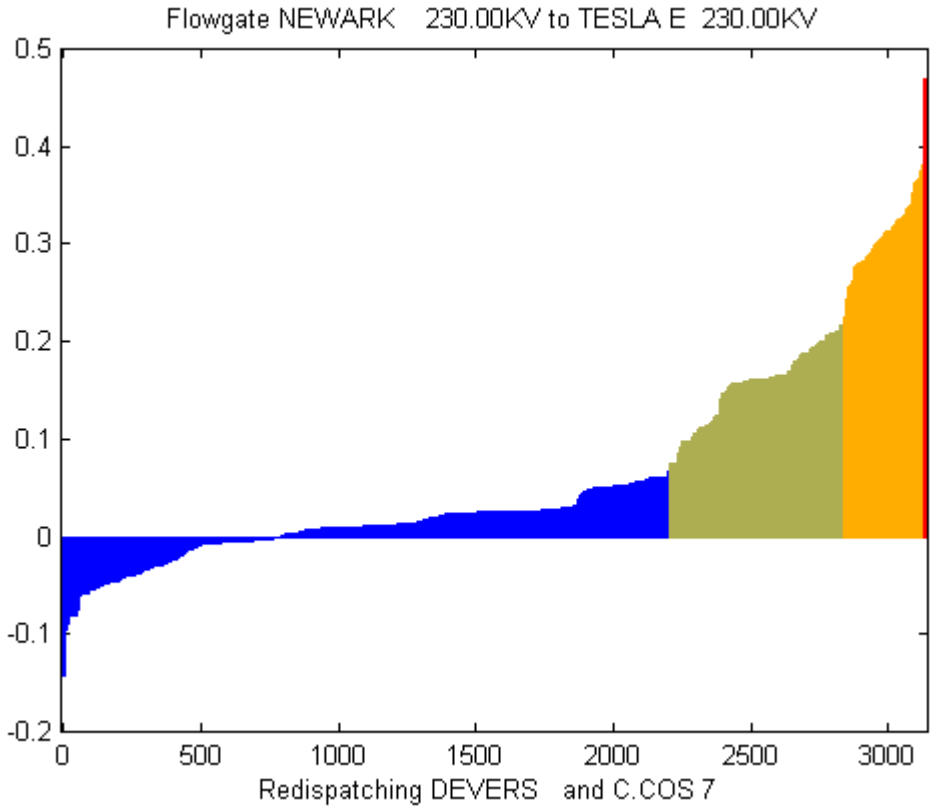

Flowgate TESLA 500.00KV to TESLA D 230.00KV
0.25
0.2
0.15
0.1
0.05
0
-0.05
-0.1
0
500
1000
1500
2000
2500
3000
Redispatching PTSB 6 and DEVERS

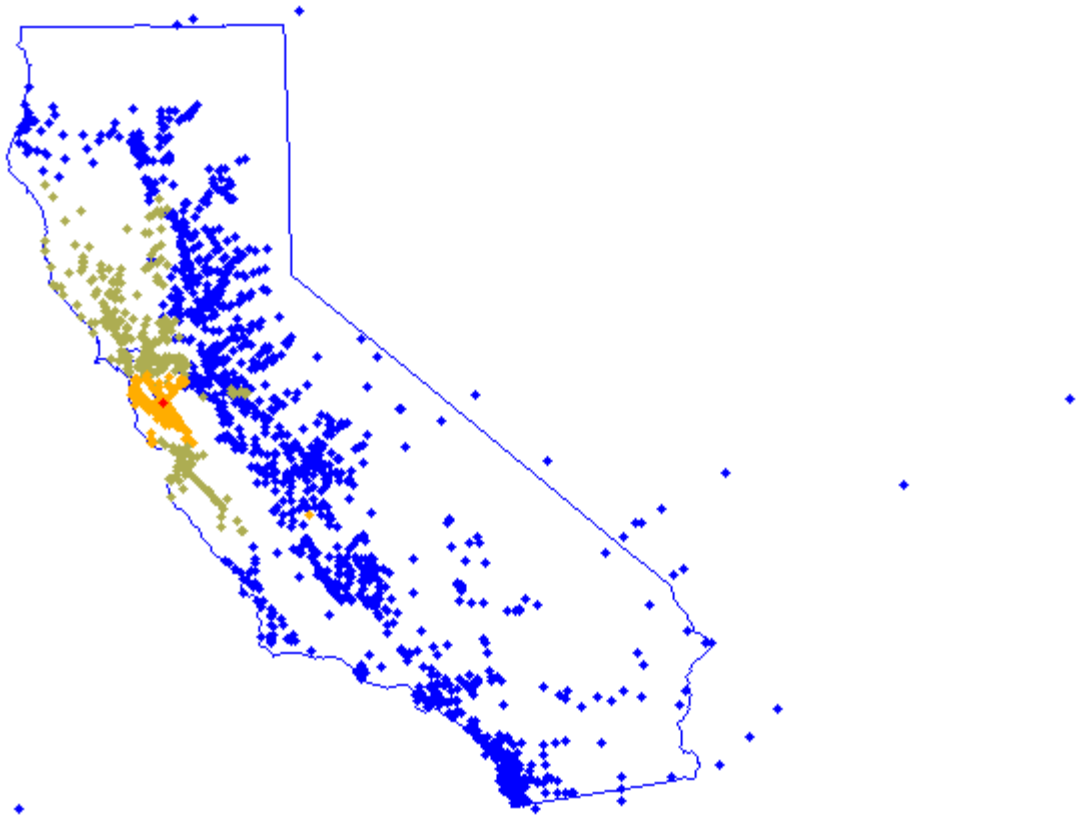


Intrazonal Congestion

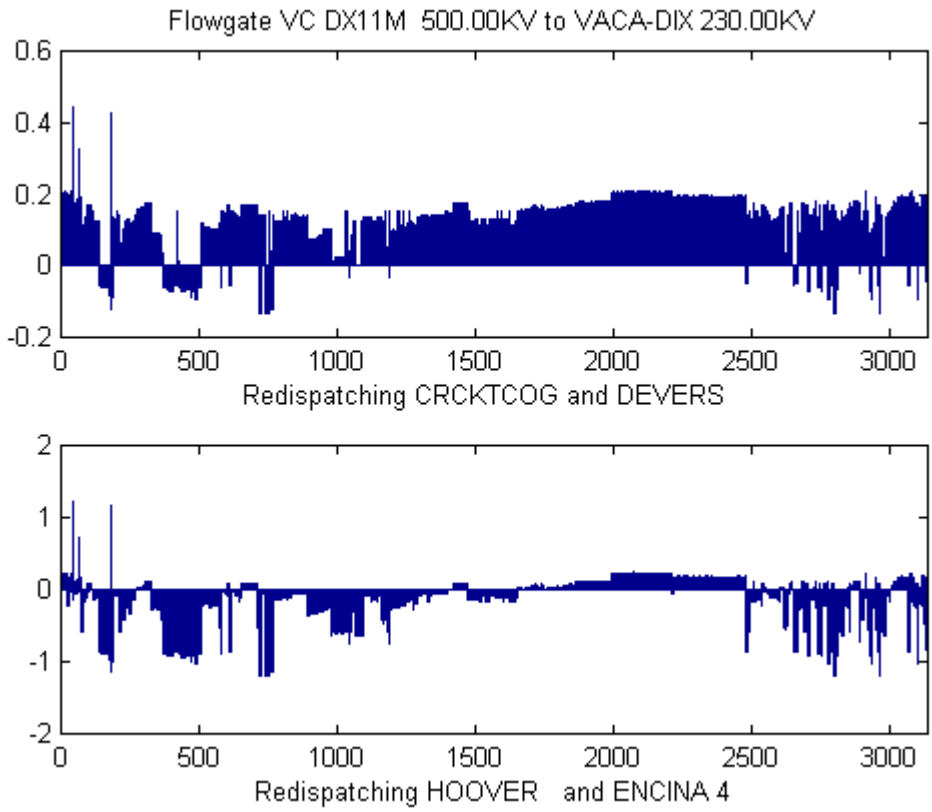


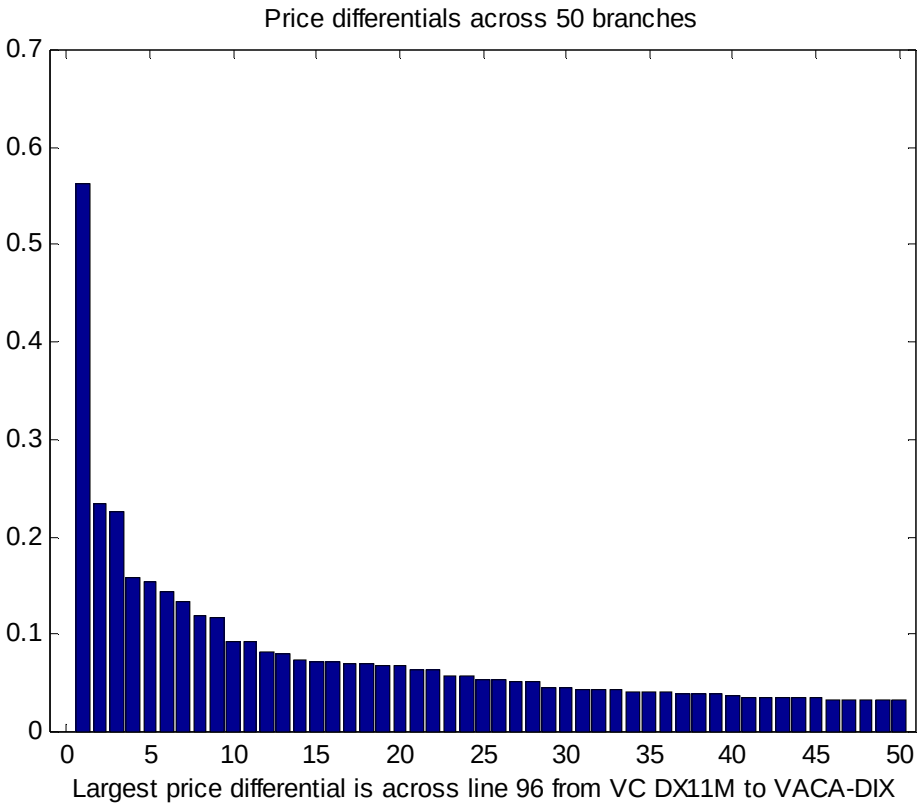

Price differentials across 50 branches
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 536 from NEWARK to TESLA E

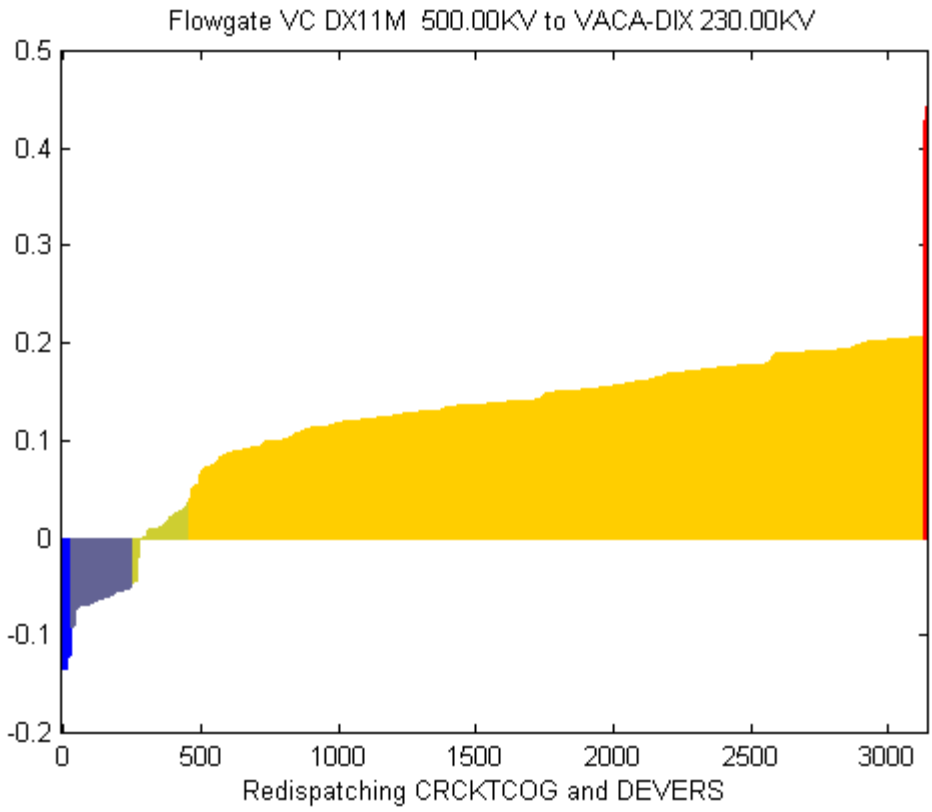

Flowgate NEWARK 230.00KV to TESLA E 230.00KV
0.5
0.4
0.3
0.2
0.1
0
-0.1
-0.2
0
500
1000
1500
2000
2500
3000
Redispatching DEVERS and C.COS 7

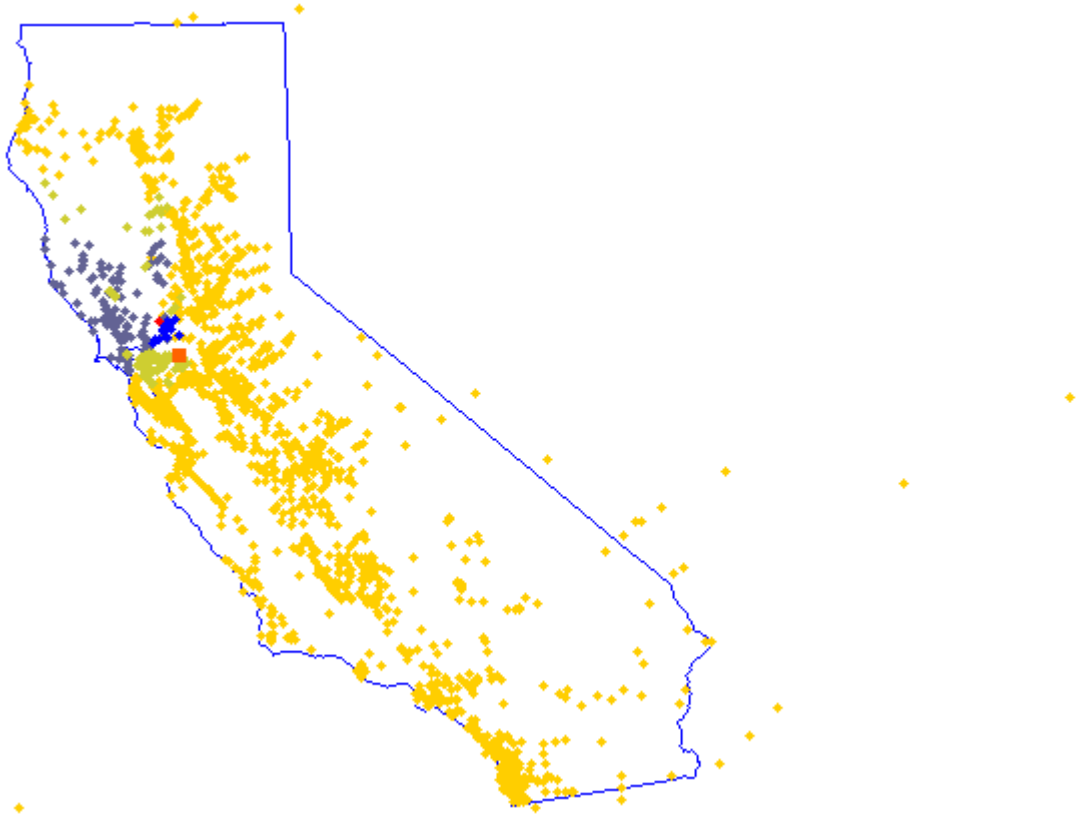


Intrazonal Congestion

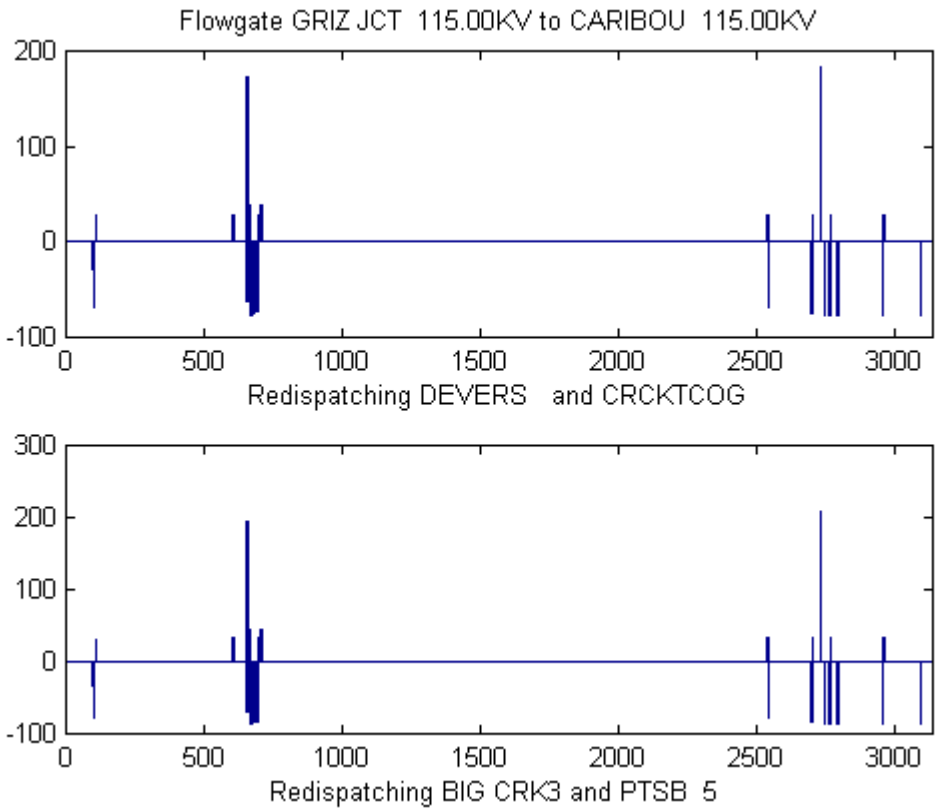


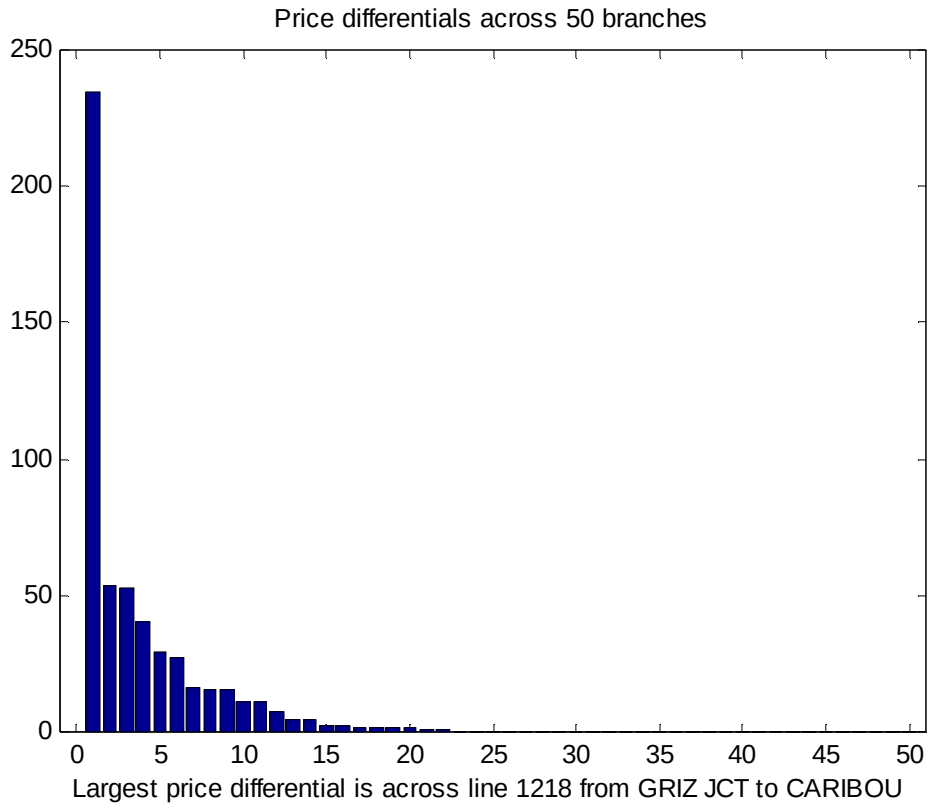

Price differentials across 50 branches
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 96 from VC DX11M to VACA-DIX

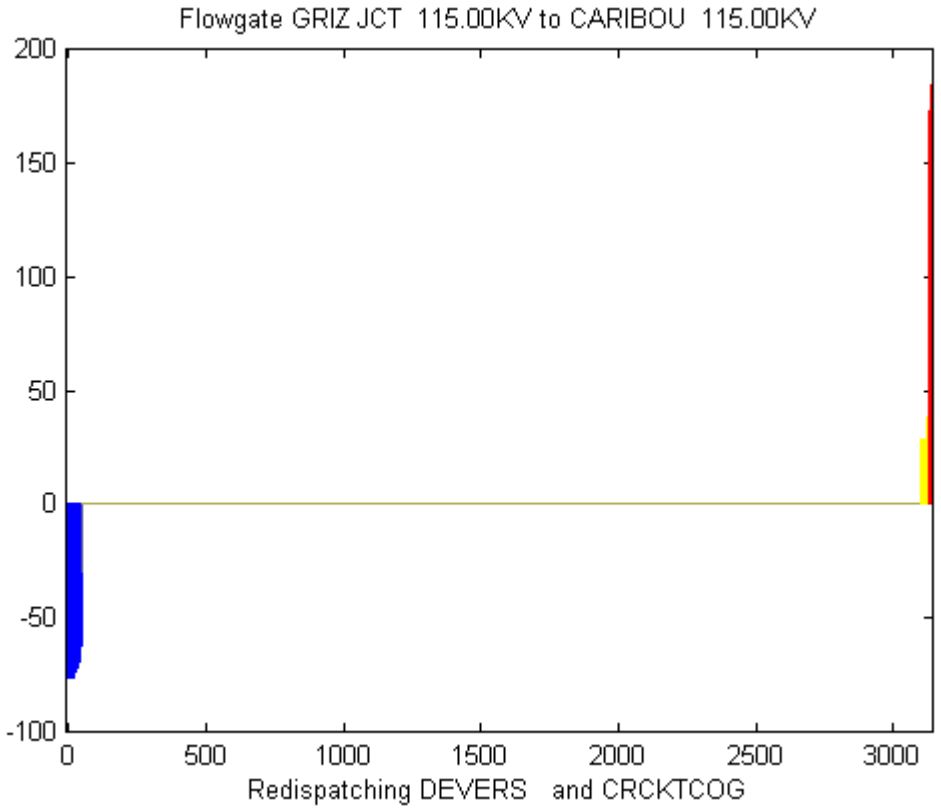

Flowgate VC DX11M 500.00KV to VACA-DIX 230.00KV
0.5
0.4
0.3
0.2
0.1
0
-0.1
-0.2
0
500
1000
1500
2000
2500
3000
Redispatching CRCKTCOG and DEVERS

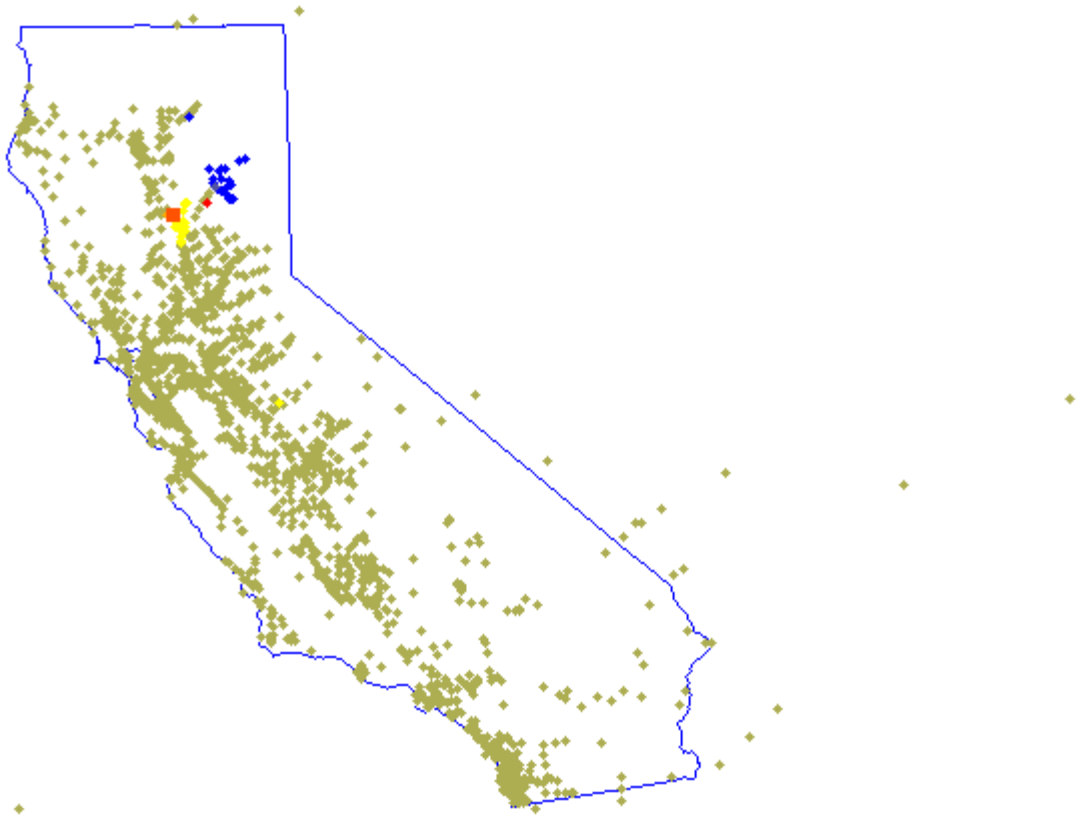


Intrazonal Congestion

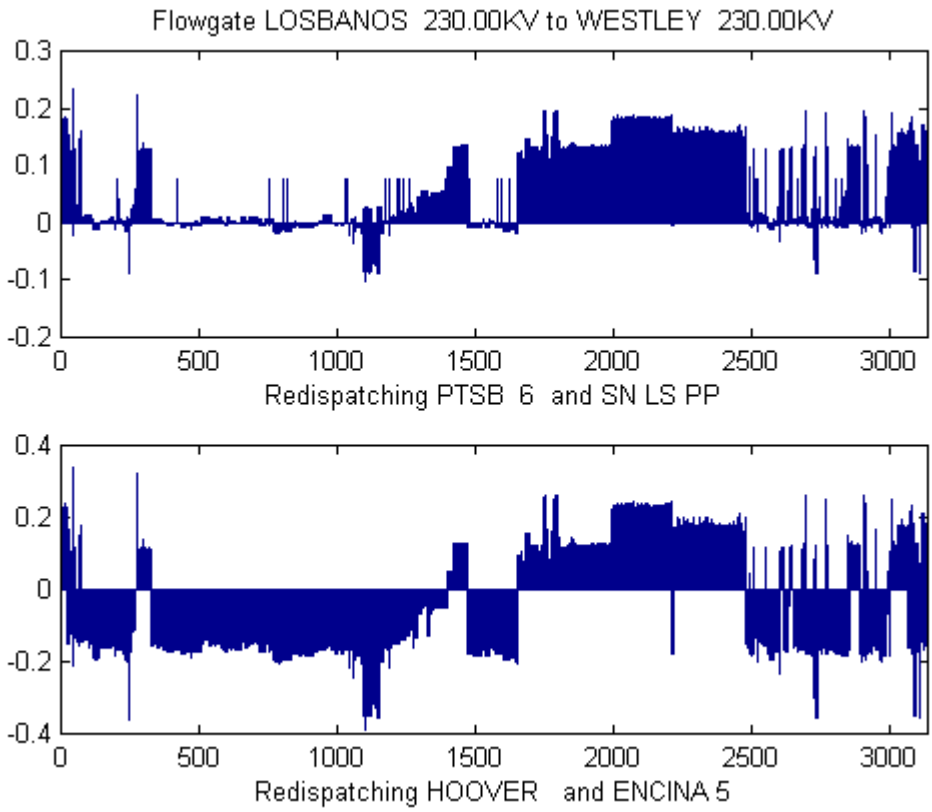


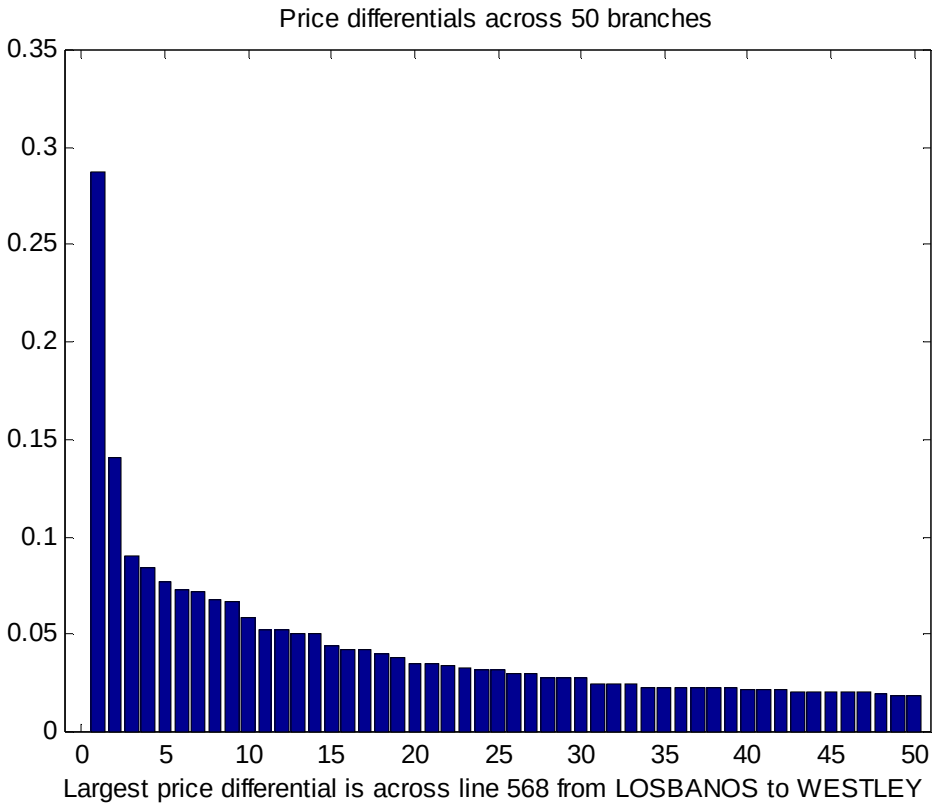

Price differentials across 50 branches
250
200
150
100
50
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 1218 from GRIZ JCT to CARIBOU

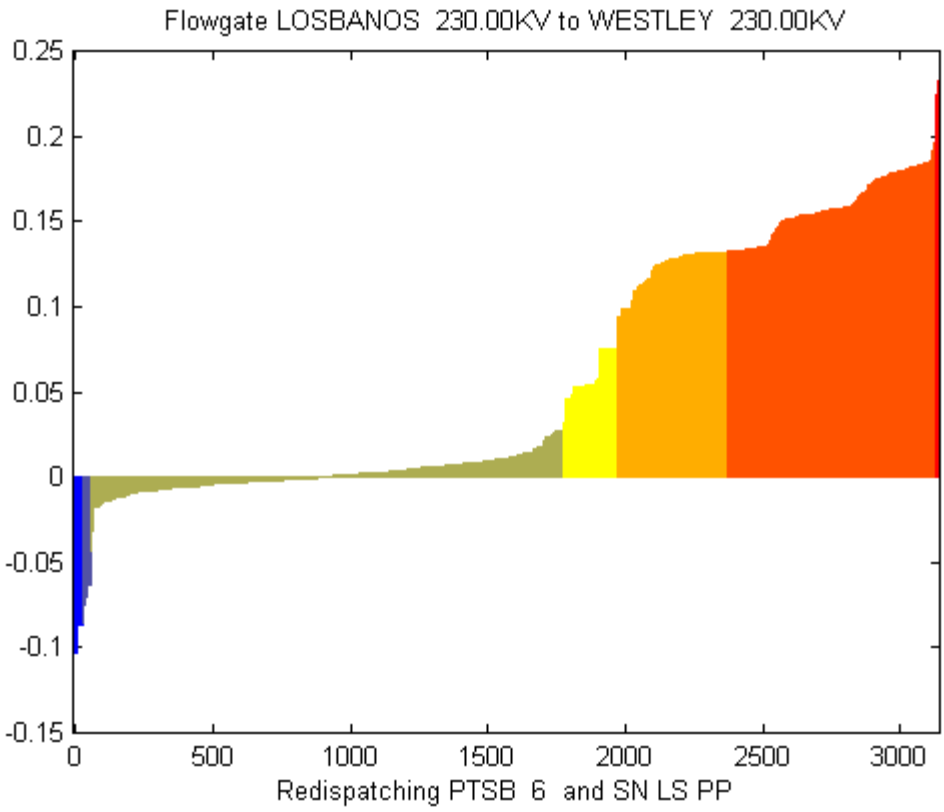

Flowgate GRIZ JCT 115.00KV to CARIBOU 115.00KV
200
150
100
50
0
-50
-100
0
500
1000
1500
2000
2500
3000
Redispatching DEVERS and CRCKTCOG

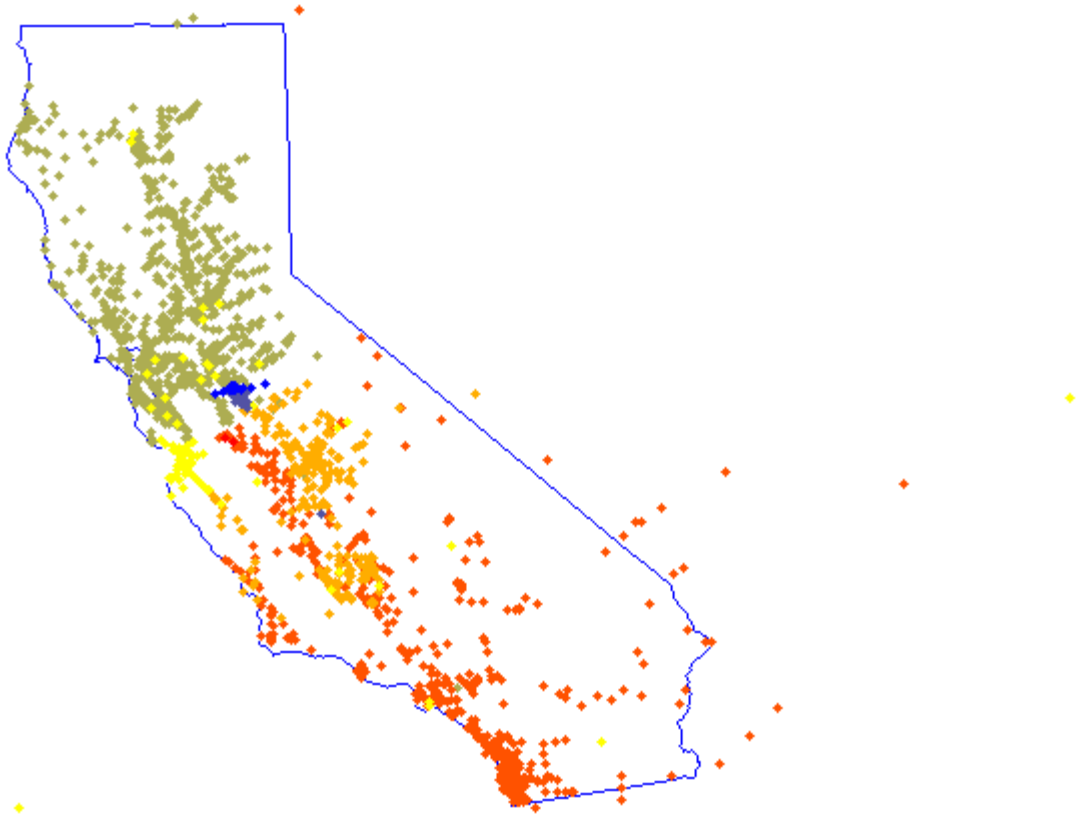


Intrazonal congestion

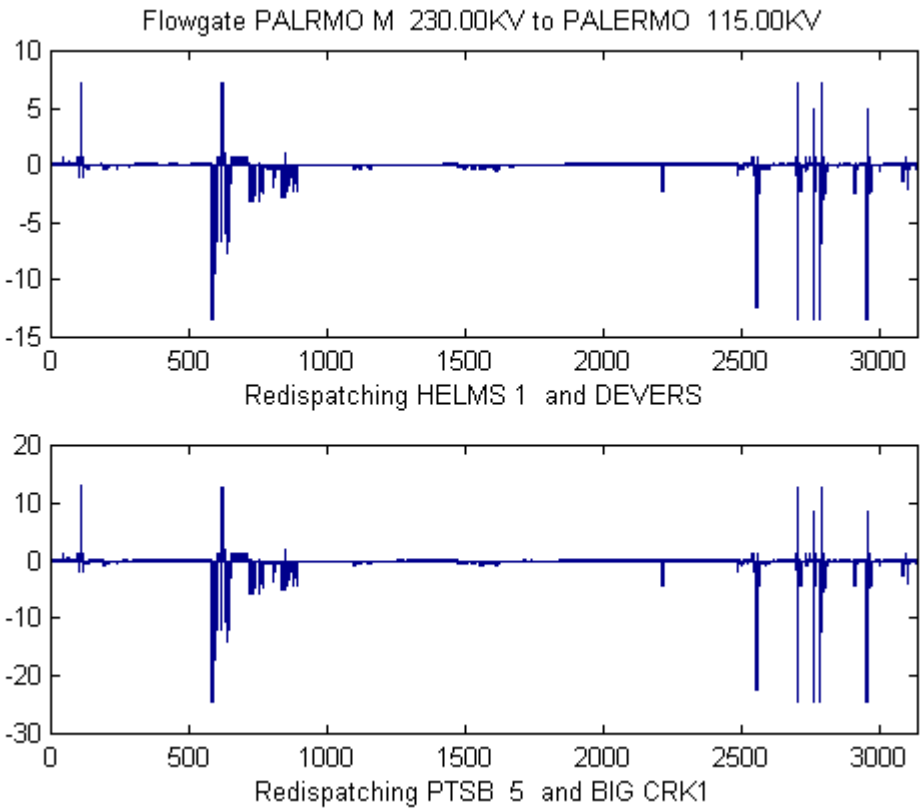


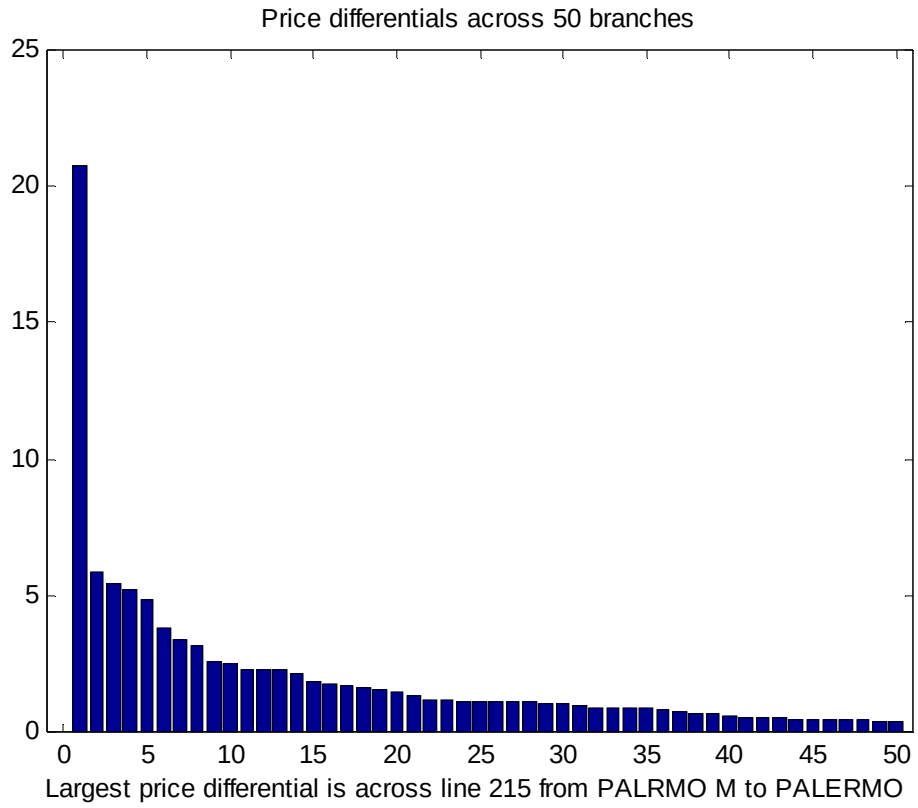

Price differentials across 50 branches
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 568 from LOSBANOS to WESTLEY

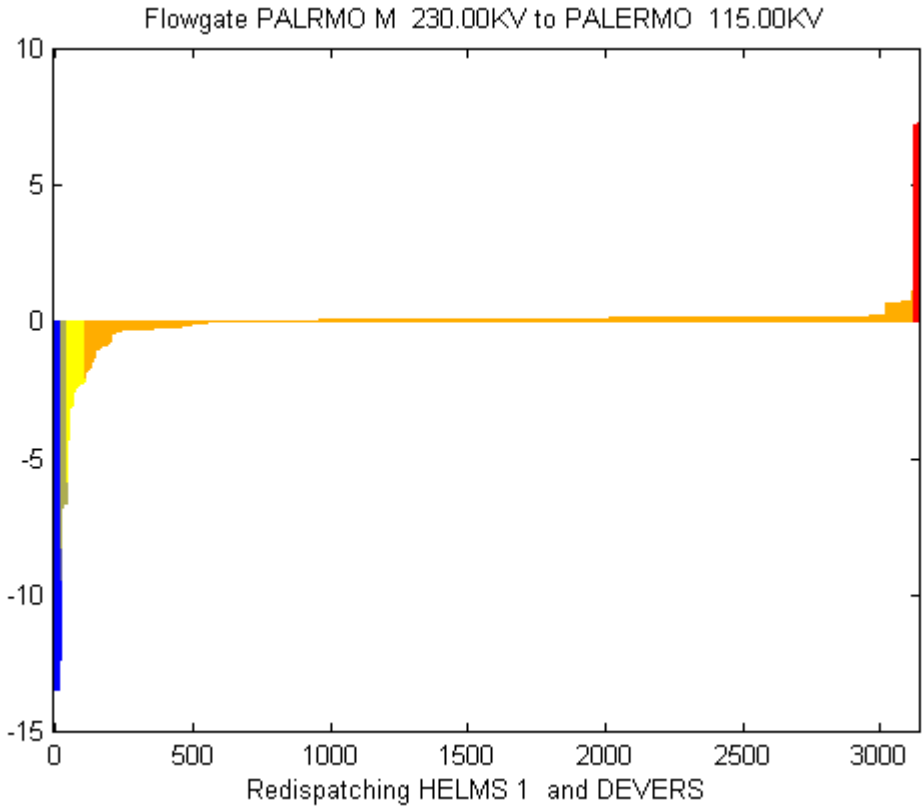

Flowgate LOSBANOS 230.00KV to WESTLEY 230.00KV
0.25
0.2
0.15
0.1
0.05
0
-0.05
-0.1
-0.15
0
500
1000
1500
2000
2500
3000
Redispatching PTSB 6 and SN LS PP



Intrazonal congestion




Price differentials across 50 branches
25
20
15
10
5
0
0
5
10
15
20
25
30
35
40
45
50
Largest price differential is across line 215 from PALRMO M to PALERMO


Flowgate PALRMO M 230.00KV to PALERMO 115.00KV
10
5
0
-5
-10
-15
0
500
1000
1500
2000
2500
3000
Redispatching HELMS 1 and DEVERS