ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

INVESTIGATION AND ASSESSMENT OF THE STATE-OF-THE-ART TECHNIQUES FOR THE RESOLUTION OF SEAMS ISSUES

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Madrid

Junio 2015

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ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

INVESTIGATION AND ASSESSMENT OF THE STATE-OF-THE-ART TECHNIQUES FOR THE RESOLUTION OF SEAMS ISSUES

Autor: Marta de Prada Gómez

Director: Professor George Gross

Madrid

Junio 2015

INVESTIGACIÓN Y EVALUACIÓN DE LAS TÉCNICAS VANGUARDISTAS EMPLEADAS PARA LA RESOLUCIÓN DE CUESTIONES FRONTERIZAS

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RESUMEN DEL PROYECTO

1. Introducción

La red eléctrica en América del Norte ha cambiado mucho en los últimos años. Hasta el final del siglo 20, la red estaba verticalmente integrada: los procesos de generación, transmisión y distribución eran llevados a cabo por una única entidad.

A finales del siglo 20 la Comisión Federal Reguladora de Energía (FERC) impuso un nuevo ambiente competitivo. Esto resultó en la creación de los Operadores Independientes del Sistema (ISOs) u Operadores Regionales de Transmisión (RTOs) para controlar y operar la red.

Una línea a través de la cual dos ISOs/RTOs vecinas conectan es conocida como una “frontera”. El precio de la generación de electricidad varía de una ISO/RTO a otra. Como consecuencia, la generación de electricidad en un momento dado puede ser más barata en una ISO/RTO que en su vecina. Esto supone una oportunidad de mejoría económica. Las ISOs/RTOs tratan de aprovechar estas situaciones para transferir energía entre ISOs/RTOs colindantes.

Las cuestiones fronterizas pueden ser definidas como barreras e ineficiencias que impiden las transacciones económicas de energía como resultado de restricciones físicas, diferencias de diseño y normas en las distintas ISOs/RTOs, etc.

Se identifican tres cuestiones fronterizas principales: infrautilización de las líneas, flujos contraproducentes y flujos paralelos. La infrautilización tiene lugar cuando la energía está fluyendo en la dirección adecuada (del lugar con menor coste de producción al lugar con mayor coste), pero queda

amplia capacidad sin utilizar. Esta capacidad podría ser utilizada para continuar reduciendo la disparidad de precios entre las dos zonas.

Los flujos contraproducentes tienen lugar cuando la energía fluye en la dirección contraria, de manera que se utilizan generadores más costosos para producir una energía que podría producirse de manera más barata en otra ISO/RTO.

Por último, los flujos paralelos tienen lugar debido a que la energía no sigue el camino que las ISOs/RTOs especifican en los contratos, sino que se guían según la topología y las impedancias de las líneas de la red. La porción de energía que se desvía de la ruta especificada en los contratos se conoce como flujos paralelos. Estos flujos pueden presentar importantes problemas operacionales cuando su duración persiste y su magnitud excede los niveles anticipados. Los flujos paralelos pueden saturar o “congestionar” las líneas de entidades intermedias, que no tomaron parte en la transacción. Estas saturaciones pueden llevar a obligar a dichas entidades intermedias a la interrupción de ciertas transacciones en sus líneas para aliviar la congestión.

Este proyecto se propone investigar la naturaleza de las cuestiones fronterizas más importantes, y las técnicas aplicadas actualmente para gestionar las cuestiones fronterizas entre dos o más ISOs/RTOs interconectadas. El proyecto incluye una valoración de dichas técnicas en términos de sus habilidades y limitaciones, además de un balance de los retos que han de ser solucionados en las respectivas áreas.

2. Metodología y resultados

La metodología utilizada para llevar a cabo la investigación es el estudio individual de las fronteras más importantes de Estados Unidos: NYISO-ISONE, MISO-PJM. Para ello se lleva a cabo una descripción del estado de la frontera, un estudio de los principales problemas y sus causas y una propuesta de soluciones y futuras tareas a llevar a cabo.

De especial importancia y gravedad es la cuestión fronteriza conocida como “flujos paralelos”. Para su estudio en mayor profundidad se ha desarrollado un modelo de un sistema de tres buses, cada uno de los cuales representa un país de Europa Central: Francia, Italia y Suiza. El objetivo es la simulación de distintas transacciones entre países colindantes, para estudiar los efectos que estos traspasos de energía tienen en líneas pertenecientes a otros países, ya que en algunos casos pueden llegar a colapsar las líneas de transmisión.

La simulación del sistema se ha realizado mediante la implementación del método de flujo de potencia de corriente continua en un código de Mat lab. Se han asumido unos valores iniciales de generación y demanda en cada país, además de un valor de flujo máximo a través de cada una de las tres líneas de transmisión que componen el sistema.

Inicialmente se ha calculado el flujo inicial a través de cada línea. Posteriormente se han ido tomando diferentes transacciones bilaterales (es decir, transacciones en las que un país exporta o “vende” energía, y otro país importa o “compra” esa energía). En cada una de esas transacciones se ha calculado qué cantidad fluiría por la línea directa que conecta los dos países, y qué cantidad fluiría por el camino paralelo. Por ejemplo, en el caso de una transacción de energía entre Francia y Suiza, se calcula qué porción fluye a través de la línea Francia-Suiza y cuál fluye a través de las líneas Francia-Italia e Italia-Suiza.

Esta evaluación se hace a través del cálculo del Factor Distributivo de Transferencia de Potencia (PTDF). Gracias esto se puede evaluar qué transacciones suponen un riesgo para las líneas de transmisión ajenas, ya que una transacción de energía entre Francia y Suiza puede llegar a saturar la línea de transmisión Francia-Italia, por ejemplo.

3. Conclusiones

Una de las principales causas de las cuestiones fronterizas es la falta de coordinación entre ISOs/RTOs a la hora de realizar transacciones. Los diferentes mercados se rigen según diferentes normas y procedimientos, que varían mucho de una región a otra. Como consecuencia, cada ISO/RTO tiene diferentes métodos y enfoques a la hora de fijar los programas de transacciones, diferentes requerimientos para los participantes de los mercados, y otras discrepancias que desalientan los intercambios externos.

Otras importantes causas de las cuestiones fronterizas son las barreras institucionales impuestas por las ISOs/RTOs y el retraso entre el momento en que una transacción es fijada y el momento en que el intercambio real de energía tiene lugar.

La mejor solución pasaría por armonizar los mercados de manera que sus normas y reglas sean más uniformes, e incluso diseñar un mercado unificado en el cual las ISOs/RTOs despachen varias áreas como una sola. Esto resultaría automáticamente en un programa óptimo para las transacciones.

Como se observa en la simulación de los flujos paralelos, estos representan una importante amenaza para todas las líneas de transmisión. La mejor solución a largo plazo para esta cuestión sería la mejora y renovación de la red, de manera que esta fuera capaz de acomodar más cantidad de transacciones, evitando así la congestión de las líneas y sus consecuentes gastos.

INVESTIGATION AND ASSESSMENT OF THE STATE-OF-THE-ART TECHNIQUES FOR THE RESOLUTION OF SEAMS ISSUES

PROJECT SUMMARY

1. Introduction

The landscape of the electrical grid in North America has changed quite a lot over the last years. Until the end of the 20th century, the electrical grid was vertically integrated: generation, transmission and distribution were handled by a single entity.

In the late 20th century a new wholesale competitive environment was imposed by the Federal Energy Regulatory Commission (FERC), which requires owners of transmission lines to make them available to allow access to utility customers. The FERC mandated the creation of Independent System Operators (ISOs) or Regional Transmission Operators (RTOs) to manage and operate the grid.

A line along which two neighboring ISOs/RTOs interface is called a “seam”. The price of generating electricity varies from one ISO/RTO to the next. As a matter of fact, it even varies from one point to another within the same ISO/RTO. Therefore, the generation of electricity at a given time may be cheaper in one ISO/RTO than in the neighboring one. Every time this happens, there is an opportunity for improved operating economics. The ISOs/RTOs intend to take advantage of these opportunities by transferring power between neighboring ISOs/RTOs.

Seams issues may be defined as barriers and inefficiencies that hold back the ability to economically transact energy, as a result of physical constraints, differences in ISO/RTO market design and rules, individual ISO/RTO operational and scheduling protocols and other distinct area practices.

Three major seams issues have been identified: tie-line underutilization, counter-intuitive flows and loop flows. Tie-line underutilization occurs when power flows in the right direction (from the lower cost region to the highest cost region), but there remains unused transfer capability that when utilized would further reduce the price disparity between the two ISOs/RTOs.

Counter-economic flows take place when power flows in the economically disadvantageous direction, i.e., from a higher cost node to a lower cost node. Therefore, costly generators are being used to produce electricity that could be produced at a cheaper price in another region.

Loop flows occur because power does not flow through the “contractual path” specified by the ISOs/RTOs when scheduling a transaction. The actual electric power flows are determined by the generation and load patterns, the topology and the line impedances on the transmission network connecting generation to load. We refer to that portion of the actual power that deviates from the scheduled flow as the loop flow. Loop flows may present operational challenges when their duration persists and their magnitude exceeds the anticipated levels. They can cause congestion in the intermediate entities’ lines, which did not take part in the transaction.

This project investigates the nature of the most important seams issues, and the current techniques applied to manage seams issues between two or more interconnected ISOs/RTOs. The project includes an assessment of those techniques in terms of both their abilities and limitations, and a statement of the challenges that need to be addressed in the respective areas.

2. Methodology and results

The methodology used for this investigation is the individual study of seams between neighboring ISOs/RTOs: NYISO-ISONE and MISO-PJM. First the state of the seam is described. After this, the main problems and their causes are investigated, and solutions are proposed for each case.

Loop flows represent an important seams issue. For its deeper study a three-bus system has been modeled to represent three countries in Central Europe: France, Italy and Switzerland. The objective is to simulate sets of transactions between two neighboring countries, to study the effects in intermediate lines.

The system simulation has been realized by implementing the DC power flow method in a Mat lab code. Initial generation and demand values have been assumed for each country and the maximum flow for each of the three transmission lines that make up the system.

First, the initial flow through each line has been calculated. Then different sets of bilateral transactions have been considered. In each of these transactions, it has been calculated which portion would flow through the direct path that connects the two countries, and which would flow through the parallel path. For example, in the case of a power transaction from France to Switzerland, it is calculated which portion flows through the France-Switzerland line and which flows through the France-Italy and Italy-Switzerland lines.

This evaluation is made by calculating the Power Transfer Distribution Factor (PTDF), which gives the opportunity to assess which transactions imply risks for intermediate transmission lines, since a power transaction between France and Switzerland could congest the France-Italy transmission line, for instance.

3. Conclusion

One of the main causes of seams issues is the lack of coordination between the ISOs/RTOs when setting the net tie schedule. Different markets have different rules and procedures that differ greatly from neighboring regions. These differences result in each ISO/RTO having different methods and approaches to set the net tie scheduled, different requirements for market participants, and other discrepancies that deter external interchanges.

Another important cause for seams inefficiencies is the large time delay between the moment when a transaction to import or to export energy is accepted by the ISOs/RTOs and when the power actually flows. This involves important financial risks for market participants, as the system conditions change greatly over the course of an hour (prices depend on factors such as weather conditions, economic conditions and availability of supply).

Institutional barriers represent another cause for seams issues. Each ISO/RTO imposes several charges on external transactions, which act on detriment of an efficient interchange.

For future efforts, the best thing to resolve tie-line issues would be to harmonize the markets so they become more uniform in terms of their rules. In the future, it would be very beneficial to design a unified market under one ISO/RTO and dispatching the multiple areas as one single area. This would mean merging the ISOs/RTOs. This would result immediately in the optimum scheduling of the tie-line, because the tie-line would be dispatched as any other internal transmission component of the unified transmission network.

As has been observed in the loop flow simulation, this issue represents an important threat to the reliability of the network. The best solution to deal with them in the long-run would be to upgrade the transmission grid. This way, the transmission lines would be able to accommodate the marginal transactions, without incurring congestion costs.

Contents

1. Introduction

1.1 The interconnected grid

The landscape of the electrical grid in North America has changed quite a lot over the last years. Until the end of the 20th century, the electrical grid was vertically integrated: generation, transmission and distribution were handled by a single entity, as illustrated in Figure 1.1.

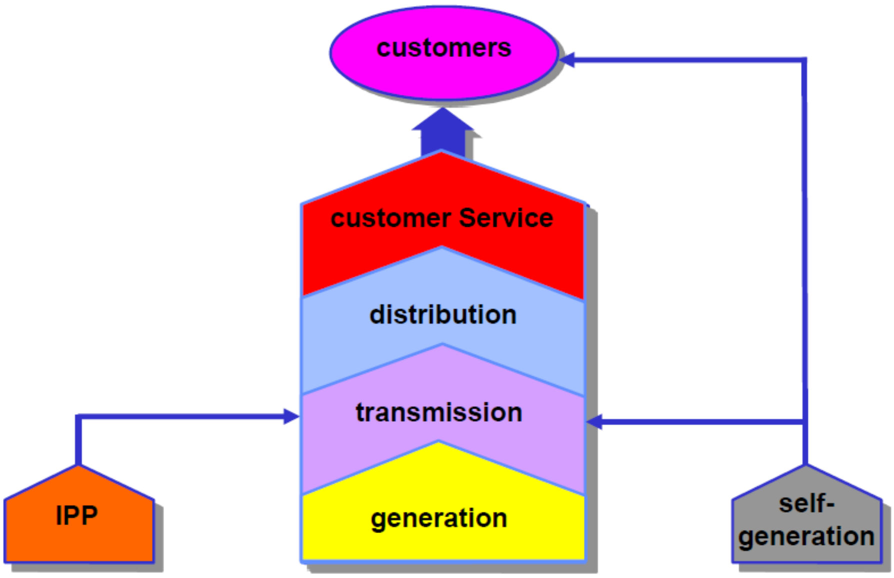

Figure 1.1- The vertically integrated utility industry structure[4]

This system, where each company provided electricity for its consumers, worked very well for a long time. The era of the 1940s, 1950s and 1960s was marked by declining rates due to several factors, such as economies of scale, technology improvements and solid national economic growth. The 1970s was a decade of change. The OPEC oil embargo of 1973 brought an end to declining electricity prices and predictable growth in demand. In addition, double digit inflation and interest rates impacted heavily the health of the industry, and environmental activist movements became a major stakeholder.

In the late 20th century a new wholesale competitive environment was imposed by the Federal Energy Regulatory Commission (FERC), which requires owners of transmission lines to make

[4] Source: Class notes for ECE 588 @ 2002-2020 George Gross, University of Illinois at Urbana-Champaign

them available to allow access to utility customers. The FERC mandated the creation of Independent System Operators (ISOs) or Regional Transmission Operators (RTOs) to manage and operate the grid.

1.2 The advent of the ISOs/RTOs

ISOs/RTOs were conceived as the way to manage the increased number of transactions that resulted from this new system. They coordinate the operation of the power system. ISOs/RTOs have no financial position in markets, which means that they do not directly participate in the electricity trade. They do not buy or sell power. They act as independent entities that administrate the payments to and from wholesale market participants. ISOs/RTOs aim to maintain the short-term reliability of the grid they operate.

Figure 1.2 shows what the United States electricity grid map looks like since the creation of these Independent System Operators. As can be seen on the map, some ISOs/RTOs comprise only one state (California ISO, for instance). But others include more than one, like PJM Interconnections, which comprises- among others- parts of the states of Illinois, Michigan, Indiana, Ohio and Pennsylvania. The white parts in the map represent the states that have not introduced the ISO/RTO system and whose markets keep working with the vertically integrated structure.

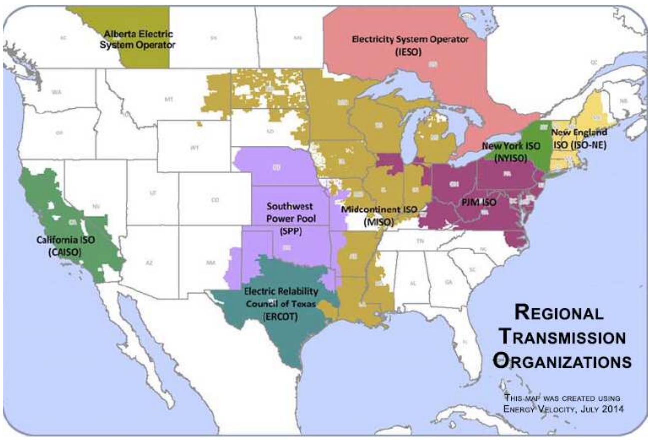

Figure 1.2- ISO/RTO map[5]

[5] Source : http://www.ferc.gov/industries/electric/indus-act/rto.asp

1.3 Seams issues

A line along which two neighboring ISOs/RTOs interface is called a "seam". The price of generating electricity varies from one ISO/RTO to the next. As a matter of fact, it even varies from one point to another within the same ISO/RTO. Therefore, the generation of electricity at a given time may be cheaper in one ISO/RTO than in the neighboring one. Every time this happens, there is an opportunity for improved operating economics. The ISOs/RTOs intend to take advantage of these opportunities by transferring power between neighboring ISOs/RTOs.

Seams issues may be defined as barriers and inefficiencies that hold back the ability to economically transact energy, as a result of physical constraints, differences in ISO/RTO market design and rules, individual ISO/RTO operational and scheduling protocols and other distinct area practices.

1.3.1 Tie-line scheduling

At each time, each node has an LMP (locational marginal price), which is the cost of producing and additional MW in that particular node. Whenever two nodes within an ISO/RTO have different LMP, it means that the line is congested (scheduled flows exceed the line's Total Transmission Capacity or TTC). As said before, whenever there is an LMP difference between two nodes that are in neighboring ISOs/RTOs, there is an opportunity for improved operating economics.

Let A_1 and A_2 represent two different ISOs/RTOs. They are connected by at least one tie-line of capacity c_t. Let LMP_1 and LMP_2 be the locational marginal prices for the respective nodes at the ends of the tie-line.

At a certain time when $LMP_2 < LMP_1$, A_1 can buy the next MW from A_2 at a lower cost than it would incur by producing it with its own generators. A_2 can benefit from selling power to A_1 at a price that is higher than LMP_2, but lower than LMP_1, so the transaction is profitable for both ISOs/RTOs.

As A_1 imports MW from A_2, LMP_1 decreases because it is replacing its high cost generation with the imported MW. And since A_1 has to accommodate additional power generation, it will have to use its high cost generators, and therefore LMP_2 will grow. Transferring power in this direction makes sense as long as $LMP_2 < LMP_1$. So, the optimal tie schedule would be the point at which $LMP_1=LMP_2$.

When power is scheduled to flow from one ISO/RTO to another, two major concerns arise:

-Tie-line under-utilization: the power flows in the right direction (from the lower cost region to the higher cost region), but there remains unused transfer capability that when utilized would further reduce the price disparity between the two ISOs/RTOs.

-Counter-economic flows: the power flows in the economically disadvantageous direction, i.e., from a higher cost node to a lower cost node.

Tie-line under-utilization and flows with counter-economic expectations imply that the two ISOs/RTOs are incurring higher production costs than necessary and are not harnessing all the benefits available.

Transactions of power between ISOs/RTOs are planned and cleared in the day-ahead market (one day before the delivery hour, during which the transaction is actually executed). One of the main causes of inefficiencies in the transmission of power is the time delay between the moment when a transaction clears in the market and the delivery hour.

Prices of electricity are very volatile. They fluctuate based on changes in supply and demand, which depend on factors such as weather conditions, economic conditions and availability of supply. These changes cause prices to fluctuate a lot over the course of an hour.

Price fluctuation makes it very difficult for market participants to schedule efficient transactions, because what was optimal when the transaction was scheduled may not be optimal when power is being delivered. This contributes to tie under-utilization and counter-economic flows and, ultimately, to the rise of total costs.

Precisely to account for price volatility, the transaction schedules can be updated until about 15 minutes before the delivery hour starts. But ISOs/RTOs usually impose deviation charges on the updates that divert the transactions from what was scheduled in the day-ahead market.

Deviation charges often cause market participants to not change their transactions, even when they know that the interchange is not optimal, because the losses derived from the charges might be higher than those caused by the inefficient interchange.

Another cause for inefficiencies is the lack of collaboration between the two areas when setting the transactions. Different markets have different rules, which cause uncertainty and risks for market participants. Also, each ISO/RTO imposes fees and charges on external transactions, increasing their cost.

1.3.2 Loop flows

Another important seam issue is loop flows. A "contract path" specifies the sequence of nodes through which the power is assumed to be routed. The actual electric power flows are determined by the generation and load patterns, the topology and the line impedances on the transmission network connecting generation to load. We refer to that portion of the actual power that deviates from the scheduled flow as the loop flow, as illustrated in Figure 1.3.

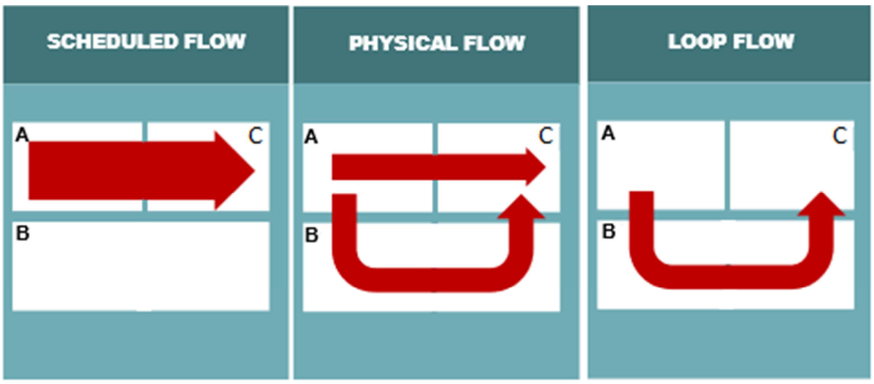

Figure 1.3- Loop flows, in comparison to scheduled and physical flows[6]

Loop flows are a direct result of interconnected system operation when multiple ISOs/RTOs are involved. Each ISO/RTO must recognize that its transmission system will have to handle a

[6] Source : https://ec.europa.eu/energy/sites/ener/files/documents/201310_loop-flows_study.pdf

reasonable level of loop flows caused by the operation of other members of the interconnection.

However, loop flows may present operational challenges when their duration persists and their magnitude exceeds the anticipated levels. Before scheduling transactions, the available transfer capability (ATC) of the line is calculated in order to know how much power can be accommodated. Taking this into account, power transactions are scheduled, trying to utilize as much capacity as possible.

Given that loop flows unevenly occupy transmission capacity throughout the entire network without recognizing jurisdiction areas, the ATC will be reduced in the areas that are not involved in the power transaction.

Loop flows can also cause congestion in the intermediate entities' lines as well as those in the sending and receiving nodes. Other impacts include the curtailment of transaction schedules and changes in system losses and net benefits.

1.4 Solutions

The ISOs/RTOs have been working for years to resolve seams issues across their interfaces. Generally, all of the solutions proposed to solve these inefficiencies can be put into one of two categories: coordination and investment.

Coordination solutions intend to resolve seams issues by increasing the coordination between ISOs/RTOs. Some of these measures are:

-Having a common internet portal through which the transactions can be scheduled.

-Eliminating exit fees from the respective markets.

-Higher frequency scheduling – this addresses the problem of the time delay between transaction scheduling (in the day-ahead market) and transaction execution (during the delivery hour).

Coordination solutions seek to resolve seams issues in the short-term, through the least cost path. But when we seek to solve these problems for good, we have to look at investment solutions. As the name suggests, they propose increasing the investment in the electricity grid with the purpose of improving it.

The proposed long-term solution is to upgrade the grid. This means installing new transmission lines so that the grid is able to accommodate all of the demand. This would solve permanently the problem with congestion, which causes high costs every year.

Each ISO/RTO may have different agreements with each of its neighboring ISOs/RTOs, depending on mutual interests. For example, in 2010 ISO New England (ISO-NE) and the New York Independent System Operator (NYISO) acknowledged that the costs of inefficient scheduling from 2006 to 2010 had been over $77 million [1]. They started working on a project to optimize the exchange of energy at their seam.

Some of the solutions that they proposed included scheduling more frequently (to account for price volatility) and changing the condition for bids to be cleared (in order to eliminate counter-intuitive flows). Their main goal is to introduce reforms that will treat seams as closely as possible to the way that internal transactions are treated.

The Mid-West Independent System Operator (MISO) and PJM Interconnection are also working on these issues. Since they are highly interconnected, they had to formulate a joint operating agreement (JOA). The document includes, among other issues, the market-to-market redispatch system (M2M). This is a short-term solution to avoid congestion.

Going back to the example where ISO/RTO A_1 has a higher LMP than A_2, A_1 values the capacity of A_2 more. If at that moment A_2 is using that capacity, then M2M curtails the transactions of A_2 to accommodate the interchange with A_1. Once this has finished and the line has been relieved, the transactions will resume. PJM and MISO's project also includes a long-term solution involving investment to upgrade the grid.

The aim of this thesis is to go into more detail about the nature and causes of seams inefficiencies, why they happen and how they can be addressed. It focuses on investigating the techniques applied to manage the seams issues across two or more specific interconnected ISOs/RTOs: MISO, PJM, ISONE, and NYISO. It also includes an assessment of the techniques both in terms of their abilities and limitations and also a statement of the challenges that need to be solved in the respective areas.

2. The NYISO-ISONE case study

2.1 Description

Established in July 1999, the New York Independent System Operator (NYISO) is responsible for the New York Control Area (NYCA), which is a part of the Eastern Interconnection, a broad area of interconnected power grids that covers most of the eastern United States and Canada.

Based in New York City, the NYISO is administered by a 10 member Board of Directors and employs over 400 people [2].

Over the years, the NYISO has been first at introducing several things, such as demand response programs, automatic mitigation programs and the economic dispatch of wind energy.

In its every day work, the NYISO has to address a number of important challenges. For instance, the mix of power supply available is very diverse, and the balance within each region is very different, as can be seen in figure 2.1.

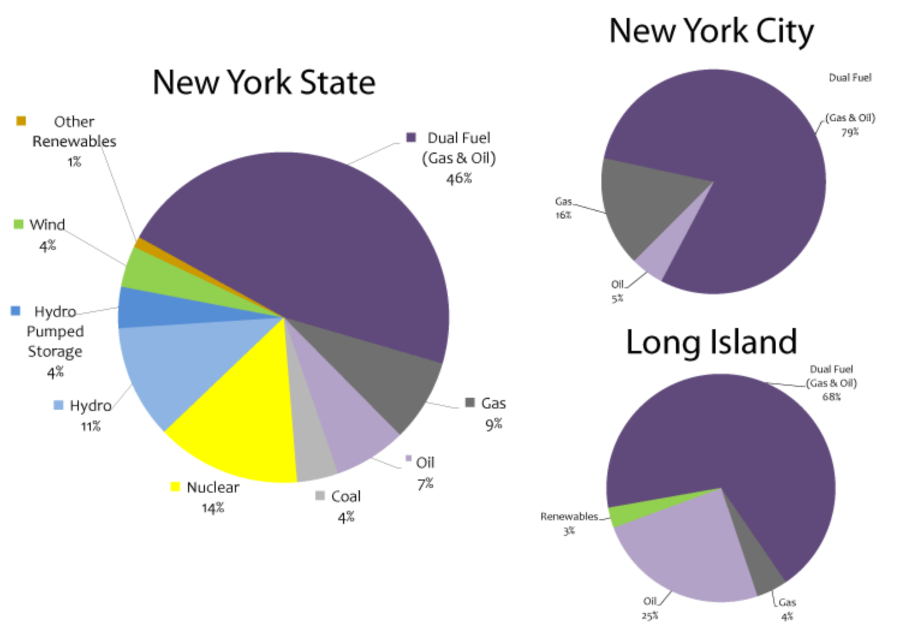

Figure 2.1- Electric generation capacity by fuel in New York in 2014[7]

[7] Source: http://www.nyiso.com/public/about_nyiso/importance_of_reliability/powering_new_york/index.jsp

East of the NYISO is located the ISO New England Inc. (ISO-NE), which serves Connecticut, Rhode Island, Maine, Massachusetts, New Hampshire, and Vermont. It was created in 1997 to replace the New England Power Pool (NEPOOL).

Today, ISO-NE relies on 350 generators, with a generating capacity of 31000 MW. It traded $10.4 billion in electricity in 2014 and has over 500 employees [3].

The importance of natural gas as a fuel in New England has rapidly increased over the years, primarily because its generators are easy to site and relatively inexpensive to build. Natural gas generation results in a decrease of emissions and bulk cost of energy. It came to represent 52% of the region's electricity in 2012.

However, natural gas generation has been reduced over the last couple of years, currently representing 44% of total electricity. This is due to several factors, the most important being that the pipes carrying natural gas into New England are reaching maximum capacity more often. Figure 2.2 depicts what the generation mix looked like in 2014 for this region.

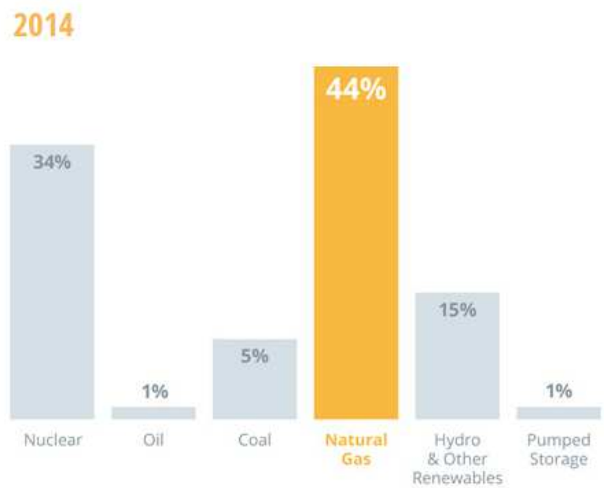

Figure 2.2- Generation mix in New England in 2014[8]

Some of the major challenges that ISO-NE will have to address in the future have to do with renewable resource integration. Renewable resource generation can help achieve

[8] Source: http://www.iso-ne.com/about/what-we-do/history

environmental goals and alleviate the volatility of electricity prices related with the fluctuation of fossil fuel prices. However, renewable energy is very intermittent and its generation often takes place in remote locations. Balancing renewable resource generation with the more reliable conventional resources is a task that ISO-NE will be facing in coming years.

2.2 Their interface

The New York and New England electricity markets are highly interconnected. Table 2.1 shows the 9 major transmission links between New York and New England. Together, these links have an approximate total capacity of 1800 MW. The majority of the capacity belongs to the New York North interface (NYN), which is the one that this report focuses on.

Interface	Network Path (From / To)	Type	Rating (kV)	Capacity (MW)
NYN	Alps NY / Berkshire MA	AC	345	Eastbound: 1400 Westbound: 1200
	Pleasant Valley NY / Long Mtn CT	AC	345	
	Rotterdam NY / Bear Swamp MA	AC	230	
	Hoosick NY / Bennington VT	AC	115	
	Whitehall NY / Blissville VT	AC	115	
	Plattsburgh NY / Grand Isle VT	AC	115	
	Smithfield NY / Falls Village CT	AC	69	
NNC	Northport NY / Norwalk CT	AC	138	100
CSC	Shoreham NY / New Haven CT	DC		330

Note: Capacity is nominal total transmission capability under normal operating conditions.

Table 2.1- Transmission lines between New York and New England[9]

The power transactions between NYISO and ISO-NE are reasonably balanced. In 2009, 44 % of these transactions (1.6 TWh of energy) flowed from New York to New England (eastbound), while the remaining 56% (1.9 TWh) flowed from New England to New York (westbound) [1].

[9] Source: http://www.iso-ne.com/pubs/whtpprs/iris_white_paper.pdf

2.3 The problem

The ISOs/RTOs commenced a project to evaluate their interchange efficiency.

The main problem that they found is that their interface often operates far below its total capacity. As explained before, this is referred to as “tie-line under-utilization”. If the power is scheduled to flow in the right direction, but the amount of MW scheduled is smaller than the optimal, it means that A1 is still producing with its own generators an amount of energy that would be cheaper to import from A2. This is illustrated in Figure 2.3.

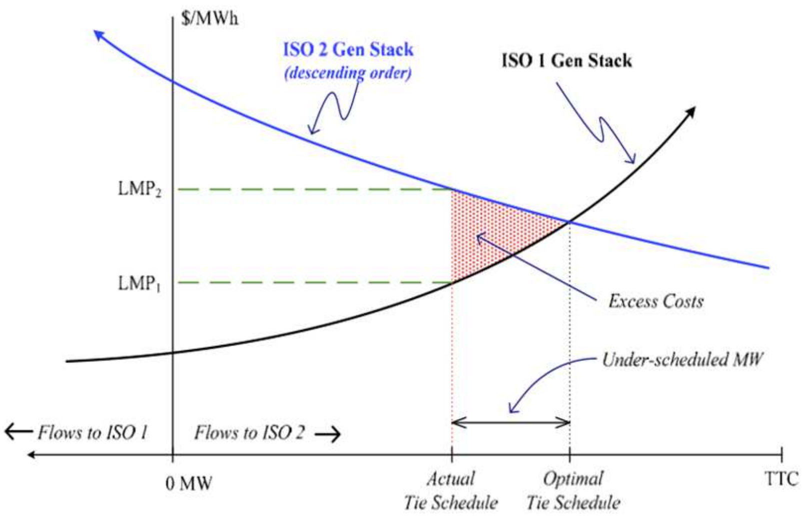

Figure 2.3- Tie-line under-utilization[10]

Counter-intuitive flows are also an issue at the interface between the two regions. If the amount scheduled is bigger than the optimal, the excess of MW flows in the wrong direction. For instance, if the optimal tie schedule (the point where the LMPs are equal) was 700 MW and 1000 MW were scheduled to flow, then the first 700 MW would flow in the right direction. But after that point the graph reverses (the exporting region’s LMP becomes larger than the importing region’s), hence it no longer makes sense to send power to flow in that direction. The remaining 300 MW flow in the wrong direction, incurring additional production costs. This case is illustrated in Figure 2.4.

[10] Source : http://www.iso-ne.com/pubs/whtpprs/iris_white_paper.pdf

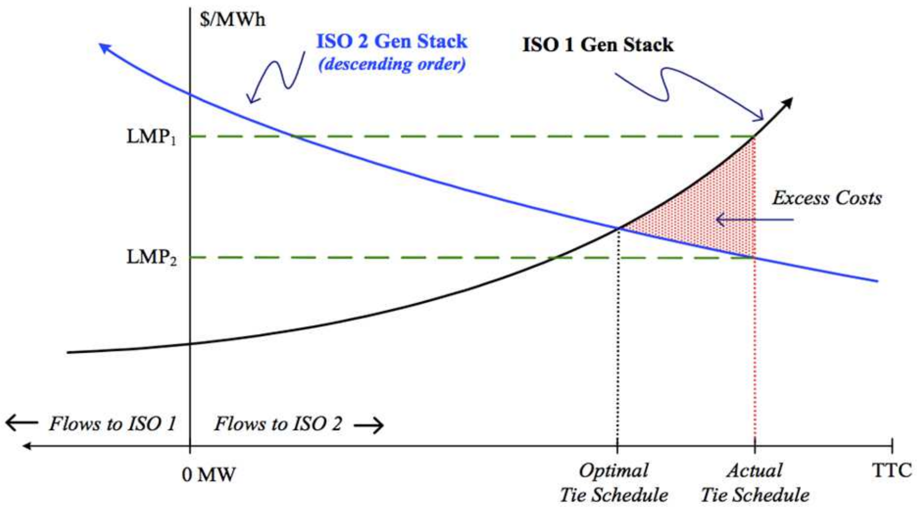

Figure 2.4- Counter-intuitive flows[11]

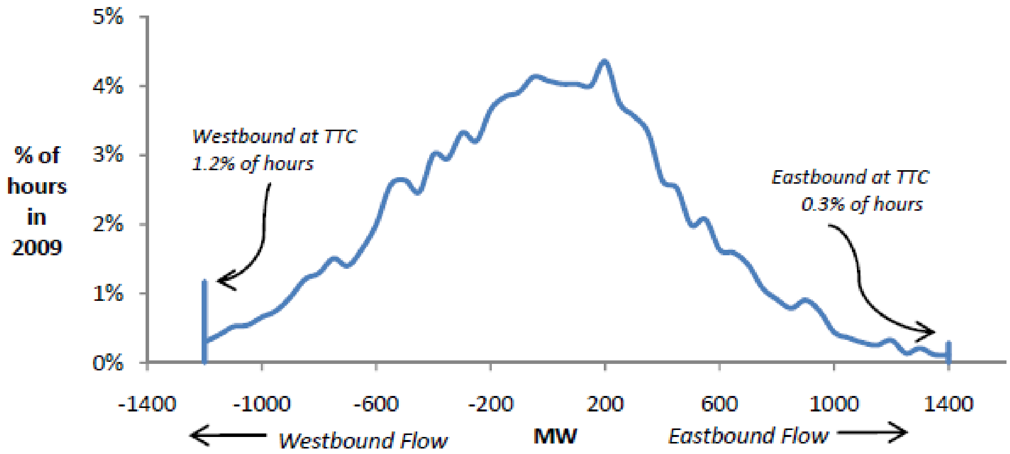

Figure 2.5- Net tie schedule on the NYN interface in 2009[12]

[11] Source : http://www.iso-ne.com/pubs/whtpprs/iris_white_paper.pdf

[12] Source : http://www.iso-ne.com/pubs/whtpprs/iris_white_paper.pdf

Figure 2.5 depicts the net tie schedule between NYISO and ISO-NE at their primary border in the year 2009. It represents how frequently (number of hours of the year in %) a certain amount of power was scheduled to flow. From this figure, several conclusions can be drawn:

-There is unused capacity at the interface during a significant number of hours of the year. The frequency distribution of flow decreases as the current increases. More than 75% of the hours of the year, the interface operates at less than half its capacity, leaving ample capacity unused.

-The lines are rarely congested. Congestion occurs when the lines reach their TTC (Total Transmission Capacity). This is 1200 MW westbound and 1400 MW eastbound. As can be seen in Figure 2.5, this limit is only reached during 1.2% of hours westbound, and 0.3% of hours eastbound. Therefore, the interface is working at its maximum capacity only about 1.5% of the year.

-The graph is centered at zero MW. Actually, the average flow per hour is 42 MW Westbound (from ISO-NE to NYISO) [1]. The power flows are very balanced, which implies that none of the two regions is predominant in power exportation.

As much as Figure 2.5 helps understand the underutilization of the transmission lines between the two regions, it only shows that ample extra capacity is available. But it does not show if it would be economically efficient for more power to flow through the interface. For that purpose, Figures 2.6 and 2.7 are shown.

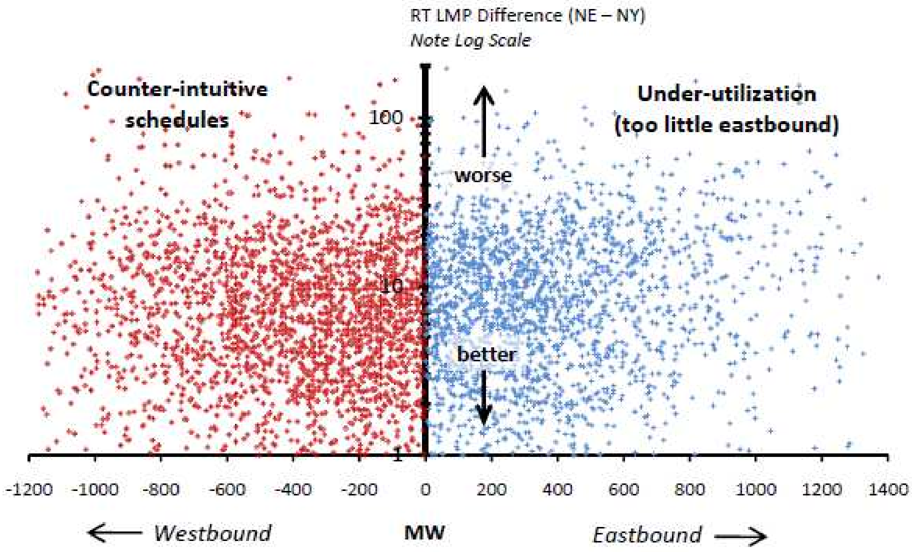

Figure 2.6- Scheduled net tie flows across NYN during the hours in 2009 when (1) New England's LMP exceeds New York's LMP and (2) the interface TTC is not binding[13]

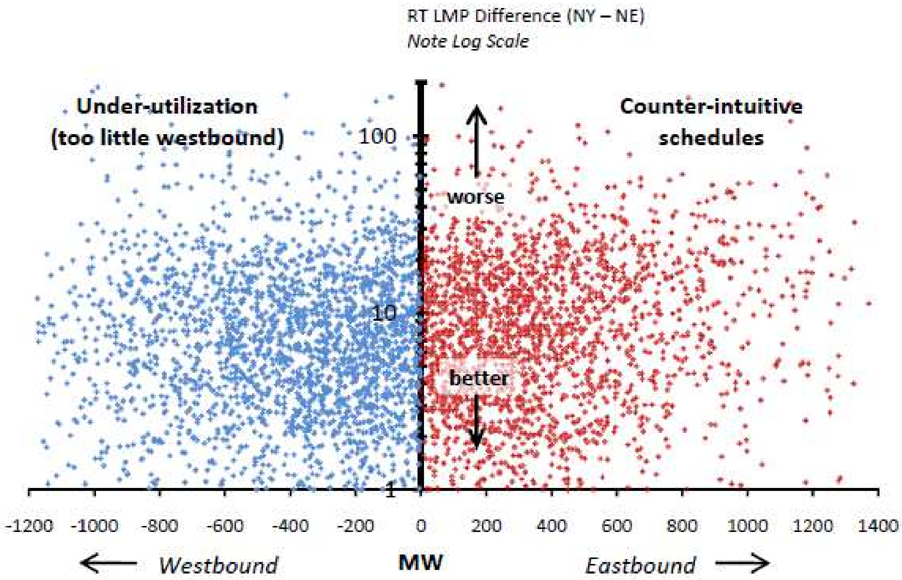

Figure 2.7- Scheduled net tie flows across NYN during the hours in 2009 when (1) New York's LMP exceeds New England's LMP and (2) the interface TTC is not binding[14]

[13] Source: http://www.iso-ne.com/pubs/whtpprs/iris_white_paper.pdf
[14] Source : http://www.iso-ne.com/pubs/whtpprs/iris_white_paper.pdf

Figure 2.6 shows the power scheduled during the hours of 2009 in which ISO-NE's LMP was higher than NYISO's LMP. Each dot represents one hour of this time. The horizontal axis represents, as in Figure 2.5, the number of MW scheduled to flow in either direction. The vertical axis represents the LMP difference in logarithmic scale.

The right part of the figure (in blue) shows the amount of time when the power is flowing in the right direction. Since in this case New England is the high-cost region, power is supposed to flow eastbound, towards ISO-NE. The left part (in red) shows the time when the power flows towards ISONY, which is the wrong direction.

As the ISOs/RTOs' objective is to reduce locational marginal price (LMP) difference to produce at the lowest possible cost, the grid would be optimally scheduled if the LMP difference between the two regions was zero at all hours. But as can be seen in the figure, nothing is further from the truth. During a significant number of hours, the power is flowing in the wrong direction. And of the remaining hours of the year, even if the power is flowing in the right direction, the scheduled amount is not enough, and therefore the LMPs do not converge.

The same conclusions apply to figure 2.7, which shows the power scheduled during the hours of 2009 in which NYISO's LMP was higher than ISO-NE's LMP. In this case, the left part shows the time when power is flowing in the right direction (westbound, towards New York, as its LMP is higher in this case). The right part represents the hours in which the power flows in the wrong direction. In this figure it can also be seen that the scheduling of power is far from efficient, as it rarely converges the prices between the regions.

Adding the results of both graphs, at the main interface between NYISO and ISO-NE the tie-lines are underutilized more than 4000 hours a year, with an average price difference between regions of $11.82 per MWh. Furthermore, power flows in the wrong direction nearly half of the time [1].

This underutilization of capacity of the transmission interface implies that the ISOs/RTOs are incurring higher costs than they would if the grid was scheduled efficiently. When the amount of power scheduled to flow is not enough to level the prices between the regions, it means that high-cost generators are being used to produce an amount of electricity that could instead be produced by the lower-cost generators in the neighboring ISO/RTO.

Counter-intuitive flows present an even bigger issue, as they imply that not only is the high-cost region producing all of its energy with its own high-cost generators, but it is also producing part of the MW needed to meet the demand of the low-cost region.

Potomac Economics conducted a study [4] that focused on the schedules between NYISO and ISO-NE in the years 2006-2010. They used a model that simulated how much energy would have to be interchanged for LMPs at the border to converge- or for the TTC to be reached, if that happened first. The results were then compared with the actual power flows that took place during those years, and the excess costs incurred for not having an optimized system were calculated.

The study estimated that, had the net tie scheduled converged prices or reached the TTC of the transmission interface at all times during the years 2006 to 2010, the total production costs would have been reduced by $77 million.

It has to be taken into account that this total reduction is not actually feasible, as converging prices at all time would require the market participants to know exactly what the LMPs of each region would be for each delivery hour, which is not possible.

The $77 million reduction has to be thought of as potential savings, but it is still significant enough so that it makes it very clear that the problem needs to be addressed.

The next section presents the causes of the inefficiencies that lead power to under-utilize the interface or to flow in the wrong direction.

2.4 Causes

There are three main causes of the inefficiencies that lead the regions to incur higher costs than necessary to meet demand. They are presented below.

2.4.1 Time delay

Under the current system, there is a large time delay between the moment when a transaction to import or to export energy is accepted by the ISOs/RTOs and when the power actually flows.

A transaction is first accepted (cleared) in the day-ahead market, which is one day before the delivery hour (during which the power flows). From the moment when the transaction clears in the day-ahead market, it can be updated until about one hour before the delivery hour starts. Therefore, there are two hours during which the transaction is fixed and cannot be changed: the hour before the delivery hour starts plus the delivery hour itself.

The fact that transactions can be updated throughout the day is because prices are very volatile and can change by the minute. This means that even if a transaction that was scheduled in the day-ahead market was economically efficient (converged prices at the border) at that time, it may not be during the delivery hour.

This time delay can lead to both under-utilization and counter-intuitive flows:

-Under-utilization: a power transaction may be scheduled to flow in the right direction (from the lower-cost region to the high-cost region). But if the price difference between regions increases during the hours in which the schedule is fixed, it means that not enough energy is flowing and there is still ample capacity for MW to flow and therefore to displace high-cost generation with low-cost generation.

-Counter-intuitive flows: if, contrary to the under-utilization case, the price difference between regions decreases during the minutes prior to the delivery hour or during it, it means that more energy than necessary is flowing, and a part of it will go in the wrong direction, increasing production costs.

It is even possible that during the time when the schedule cannot be changed, the LMPs reverse and the high-cost region becomes the low-cost region. In that case all of the power flows in the wrong way.

From the perspective of a market participant submitting an offer to transact power from one ISO/RTO to the other, this time delay implicates a financial risk. If the scheduled power becomes inefficient, the market participant (MP) loses money. This worsens the issue with under-utilization, as MPs may choose to schedule a smaller amount of MW than it seems to be economically efficient, for fear of prices changing too much during these hours.

2.4.2 Non-economic clearing

This section refers to the system used by the ISOs/RTOs to determine whether a transaction is accepted (cleared) or not.

Requests are submitted separately to each ISO/RTO. For example, if a MP wants to schedule power to flow from ISO-NE to NYISO, they have to submit two separate requests: one to “buy” or export to ISO-NE, and another one to “sell” or import to NYISO. The transaction clears if both requests ISOs/RTOs are accepted by the correspondent ISO/RTO. There is no coordination between the regions when clearing transactions.

A transaction is accepted if two conditions are satisfied:

-The offer to buy is higher than the exporting region’s LMP. This condition has to be checked by the exporting ISO/RTO (in the example, it would have to be checked by ISO-NE).

-The offer to sell is lower than the importing region’s LMP. This condition has to be checked by the importing ISO/RTO (NYISO in the example).

The transaction will clear if both this conditions are checked. However, satisfying these two conditions does not necessarily mean that a transaction is economically efficient.

The condition that would have to be fulfilled is that the importing region’s LMP exceeds the exporting region’s LMP. This condition ensures that the power flows from the low-cost generation region to the high-cost generation region.

For the clearing system to be efficient and able to lower production costs for both regions, it would have to check the mentioned condition.

2.4.3 Transaction costs

The ISOs/RTOs impose several costs on external transactions, which are detrimental to efficient interchange. Some of these costs are:

-General 'uplift' costs per MW scheduled imposed on external transactions.

-Financial impact charges imposed on transactions that fail to be accepted during the clearing process.

-ISO/RTO scheduling fees paid by market participants. Since external transactions involve both ISOs/RTOs, MPs have to face these fees twice.

As market participants are aware that they will have to face a lot of charges for their inter-regional transactions, they will be very cautious when scheduling them. They may not schedule a transaction unless they are certain that the economic benefit they will obtain is higher than the transaction cost they will have to pay. This leads to a lot of transactions remaining unscheduled, leading to under-utilization.

2.5 Solutions

This section focuses on the solutions that NYISO and ISO-NE have considered to resolve the inefficient schedules that occur at their seam. Two solutions [1] call for special attention. Those are tie optimization and coordinated transaction scheduling (CTS). Any of these solutions would lead to lower production costs than the current system.

2.5.1 Tie optimization

The main idea behind tie optimization is to deal with the transmission interface between the two regions as close as possible to the way they deal with transmission within each ISO/RTO.

To achieve this purpose, new options would need to be provided to the market participants, to protect themselves (hedge) against financial risk and to eliminate obligations that sometimes lead MPs to submit schedules that are not efficient.

The main element in the tie optimization solution is high frequency scheduling (HFS). This is a system that sets the net tie schedule as close to real time as possible, and updates it frequently.

This way, the system can account for price volatility and adjust the net tie schedule accordingly, in order to avoid setting the schedule in an inefficient way.

High frequency scheduling proposes to update the net tie schedule approximately 5 to 10 minutes before the power flows (during the delivery hour), and fix schedules for 15 minute intervals, instead of 1 hour intervals as the current system does.

There is a pre-scheduling process during which the ISOs/RTOs jointly determine the net tie schedule for the next schedule interval. From this process they also obtain “advisory” net tie schedules for the subsequent intervals. These “advisory” net tie schedules serve as information to help evaluate the net tie schedule for the next intervals.

The process that the Tie Optimization solution uses to determine the optimal net tie schedule consists of several steps:

-Step 1 (Pre-schedule): ISO-NE determines its interface dispatch-rate schedule, which is the LMP increments and decrements depending on how the power is scheduled to flow. The interface dispatch-rate schedule describes how ISO-NE’s LMP at the interface with NYISO will vary depending on how much power flows.

Any constraints in the ISO-NE tie flows are considered to determine this schedule. ISO-NE passes this information on to NYISO.

-Step 2 (Tie Optimization): NYISO adds the info facilitated by ISO-NE to its own generation supply curve. It then determines the net tie schedule target for each ISO/RTO for the following 15-minute interval. This step also produces “advisory” tie schedule targets for the 3 subsequent 15-minute intervals.

NYISO then passes this information on to ISO-NE, incorporating any constraints that may affect its transmission lines.

-Step 3 (real-time dispatch): each ISO/RTO runs its internal real-time dispatch, which uses the optimized net tie schedule from step 2 as input to obtain a ramp profile for the next 10 minutes.

-Step 4 (pre-schedule update): ISO-NE performs step 1 again, this time taking into account the information obtained in the previous steps. That way, ISO-NE comes up with an optimized interface dispatch-rate schedule.

-Step 5 (tie optimization update): NYISO performs step 2 again, using the updated system information. This step produces new net tie schedule targets and “advisory” net tie schedule targets.

-Step 6 (real-time dispatch): each ISO/RTO runs its internal real-time dispatch, this time taking into account the updated information that the system has obtained during the last steps.

The reason why the pre-scheduling step is performed by ISO-NE and the tie optimization step is performed by NYISO is technological. The current working technologies that each ISO/RTO has allow ISO-NE to carry out the pre-scheduling step more effectively than NYISO would, while it makes more sense for NYISO to perform the tie-optimization step.

The most important point of tie optimization is that it provides the system with a tie schedule target that is not fixed for an hour, as it is today. Instead, this solution updates its net tie schedule every 15 minutes, to produce ramp windows that will smoothly adjust from one interval to the next. This way, tie optimization enables the system to respond against the price volatility that exists in the energy market.

Under the current system, as tie schedules are fixed for one-hour periods, there is no reaction to the fluctuation of locational marginal prices (LMP) at the border between the two regions. Whenever these fluctuations change the optimal schedules, the current system cannot react to these changes until the hour has finished. Higher frequency scheduling reduces this interval to only 15 minutes, which can greatly reduce production costs.

2.5.2 Coordinated transaction scheduling

The second solution that has been proposed to resolve the inefficiencies that take place at the border between NYISO and ISO-NE is coordinated transaction scheduling (CTS). This solution has more in common with the current system than tie optimization.

Coordinated transaction scheduling has some elements in common with tie optimization, such as high frequency scheduling (HFS) and the elimination of some of the charges that the ISOs/RTOs apply to external transactions and which discourage trade. However, CTS differs from tie optimization in the way that the transactions are accepted (cleared) and in the method used to set the net tie schedule at the seam.

The CTS solution introduces an innovation in the way that market participants submit their offers: the interface bid format. An interface bid is a unified transaction to buy and sell power that is submitted simultaneously to both sides of the interface.

With the current system, market participants submit a request to "buy" at the exporting side of the interface, and a separate request to "sell" at the importing side. The transaction clears if both requests are accepted by the respective ISOs/RTOs. With this new proposal, there would only be one request, which would be jointly cleared by both ISOs/RTOs at the same time.

The interface bid is composed of three numbers, which represent a price, a direction and a quantity. The first is the minimum price difference that the market participant is willing to accept to make the transaction. The second number indicates whether the transaction is westbound (from ISO-NE to NYISO) or eastbound (from NYISO to ISO-NE). The quantity is the number of MW that the transaction transfers from one region to the other.

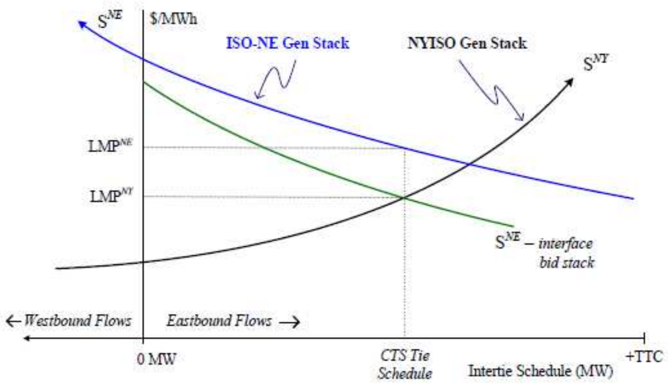

Figure 2.8- Determining net tie schedule with CTS[15]

[15] Source: http://www.iso-ne.com/pubs/whtpprs/iris_white_paper.pdf

The two solutions differ at how they determine the net tie schedule for a certain delivery hour. Tie optimization would set the schedule at the point where the two ISOs/RTOs' generation supply stacks cross. Instead, CTS sums up all of the offers to export power at the exporting side of the border, and then subtracts them to the importing ISO/RTO's supply curve.

Figure 2.8 shows what the case in which at zero interchange, ISO-NE has a higher LMP than NYISO. Therefore, ISO-NE has higher-cost generation and must be the importing region. Power must flow eastbound, to displace the high-cost generators in ISO-NE for the low-cost generators in NYISO.

To determine the schedule, all of the interface bids to export power from NYISO are summed up, and subtracted from the ISO-NE generation supply curve, to obtain the green curve in the figure. Then, the schedule is set at the point where this curve crosses NYISO's generation supply curve.

An interface bid is cleared if the offered price (first of the three numbers) is less than the expected LMP difference when the schedule is set. This means that the bids that fall on the left side of the CTS Tie Schedule point will be accepted, whereas those which fall on the right side will be denied.

Under the CTS solution, interface bids are pooled to both ISOs/RTOs at the same time. This means that there would need to be a common bid submission platform for market participants to submit their interface bids, and for the ISOs/RTOs to jointly accept them.

2.6 Conclusion

To decide which of the two solutions (tie optimization and coordinated transaction scheduling) would be better to resolve the seams issues at the border of the two regions, it is important to see which one is more efficient.

The answer is that tie optimization is the most efficient, as it converges the price difference between the two ISOs/RTOs. Since the net tie schedule is set at the point where the two locational marginal prices (LMPs) are equal, the schedule is always optimized at the time when it is set (though it may not be optimal when the delivery hour starts, due to price volatility).

However, as it can be seen, CTS does not converge the LMPs between regions. As it can be seen in Figure 2.5, the net tie schedule is always set at a point where there is still a price difference. The importing side still has a higher LMP than the exporting side.

By leaving the importing side LMP higher, CTS ensures that the schedule will not be set to flow in the wrong direction (from the higher-cost region to the lower-cost region). It solves one of the root causes of the inefficiencies: non-economic clearing. Therefore, CTS solves the problem of counter-intuitive flows. However, having a price difference means that the line is underutilized. There is still available capacity to transfer power between regions, which would reduce production costs for the ISOs/RTOs.

On the other hand, tie optimization does converge the expected LMPs. With this solution, both tie-line underutilization and counter-intuitive flows are resolved, which makes this the most efficient solution to address the inefficiencies in the power interchanges between NYISO and ISO-NE.

3. The MISO-PJM case study

3.1 Description

The Midcontinent Independent System Operator (MISO) is one of the largest and most important ISOs/RTOs in the United States. It was first established in September 1998. In December 2001, the Federal Energy Regulatory Commission (FERC) approved the MISO as the nation's first Regional Transmission Operator (RTO).

The MISO is responsible for operating the electrical grid in a large area of the United States and Canada. This area covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, Illinois, Indiana, Michigan and parts of Montana, Missouri, Kentucky, Arkansas, Texas, Louisiana and Mississippi.

Based in Carmel, Indiana, the MISO is governed by an independent eight-member board of directors and it employs over 700 people. Its generation capacity is over 130,000 MW [5], and it serves more than 39 million people.

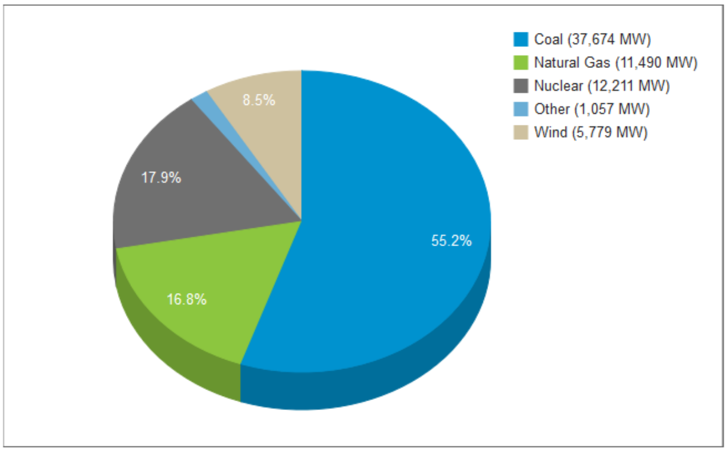

Figure 3.1- Percentage of total MWs supplied by the listed resources in the MISO footprint[16]

[16] Source :

https://www.misoenergy.org/MARKETSOPERATIONS/REALTIMEMARKETDATA/Pages/FuelMix.aspx

The MISO can be divided to three regions: North, Central and South. The North and Central regions have coal as their major energy resource. In 2013 the South region- whose major source is natural gas- was introduced to the MISO.

This increase in the diversity of the fuel mix of the ISO/RTO led to less exposure to price volatility. This allows the MISO to incur lower production costs and therefore to be able to meet demand with lower prices for consumers. Figure 3.1.a represents MISO’s fuel mix.

The MISO is bordered to the East by the Pennsylvania-New Jersey-Maryland Interconnection (PJM Interconnection). This ISO/RTO serves all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia, ensuring reliability for more than 61 million people.

PJM was approved in 1997 by the FERC as the nation’s first fully functioning ISO. Headquartered in Valley Forge, Pennsylvania, PJM is governed by a board of managers, which consists of 10 members.

PJM is currently the world’s largest competitive wholesale electricity market, having a generating capacity of more than 183 GW and more than 800 companies as members [6].

PJM’s vision is “to be the electric industry leader- today and tomorrow- in reliable operations, efficient wholesale markets, and infrastructure planning”[6].

In recent years, the world has seen a diversification of the generation mix, as coal-fired power plants retire and natural gas-fired resources increase. This transition is especially rapid in the PJM region. Natural gas already represents more than 60% of the new resources in PJM.

PJM Interconnection President and CEO Terry Boston declared that natural gas will soon replace coal as the primary fuel in PJM’s generation mix. Figure 3.2 depicts PJM’s current generation mix.

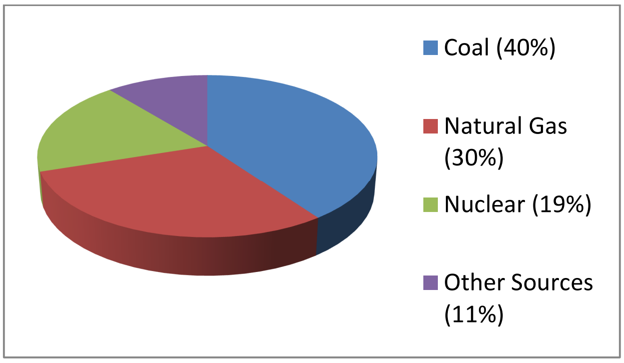

Figure 3.2- PJM's fuel mix

3.2 Their interface

The Midwest ISO and PJM Interconnections have highly interconnected markets. To accurately evaluate the efficiency of the interchange schedules between the two ISOs/RTOs, it is essential to know the available transfer capability at their border in the two directions.

One of the many disparities between the two ISOs/RTOs is the models and approaches they use to estimate their available capacity. For this purpose, PJM has developed the Capacity Emergency Transfer Limit (CETL), whereas MISO has developed two different approaches: the Capacity Import Limit (CIL) and the Capacity Export Limit (CEL). It can be expected that, as the two regions use different modeling approaches, their estimates will differ.

Interface Point Between PJM and MISO	Capacity Transfer Capability	
	MISO → PJM *(UCAP MW)*	PJM → MISO *(UCAP MW)*
MISO ↔ ComEd	4,300	n/a
MISO ↔ Rest of PJM	2,000	n/a
MISO ↔ All of PJM	6,300	n/a

Table 3.1- MISO Estimate of 2014/15 transfer capability Using PJM CETL Method[17]

[17] Source : https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Preliminary%20Brattle%20Report_MISO-PJM%20Capacity%20Seam%20Definition%20-%202011-12-06.pdf

Interface Point Between PJM and MISO	Capacity Transfer Capability	
	MISO → PJM (UCAP MW)	PJM → MISO (UCAP MW)
MISO ↔ ComEd	n/a	n/a
MISO ↔ Rest of PJM	2,800	n/a
MISO ↔ All of PJM	5,300-5,700	n/a

Table 3.2- MISO Estimate of 2014/15 transfer capability Using MISO CIL and CEL Method[18]

MISO has developed estimates for the 2014/2015 transfer capability or unforced capability (UCAP) in the MISO-PJM direction of the interface. The ISO/RTO has conducted two different studies: one by using PJM's CETL approach, and another one using its own CIL and CEL approaches. The results of these estimates can be seen in Tables 3.1 and 3.2, respectively.

The study focuses on the interchanges at the interface that flow from MISO to PJM, both the Commonwealth Edison (ComEd) area and the rest of PJM. Taking into account the results of the estimates obtained by each approach, MISO has estimated that the interface has 5300-6300 MW of capacity transfer capability for power to flow from MISO to all of PJM [7].

3.3 The problem

Historically, PJM capacity prices have been on average $30 per kW-year above those in the Midwest ISO [7]. This price disparity creates a strong incentive for MISO generators to export their lower-cost generation to PJM, for the benefit of both ISOs/RTOs.

If the market was efficiently optimized, MISO would export power to PJM until the locational marginal prices (LMPs) of the two regions at the border converged, or the total transfer capability (TTC) of the tie-lines was reached and no more power flows could be accommodated.

[18] Source : https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Preliminary%20Brattle%20Report_MISO-PJM%20Capacity%20Seam%20Definition%20-%202011-12-06.pdf

However, power flows from MISO to PJM have been far below the TTC of the interface. They also do not eliminate the price difference between the regions.

During the 2014/15 delivery year, only 400-900 MW of power were transferred from the Midwest ISO to PJM Interconnection. This quantity is far below the 5300-6300 MW of estimated transfer capability in that direction at the interface. This indicates that over 4000 MW of additional net capacity sales could have been realized during the 2014/15 delivery year, but remained unused.

This large amount of unused transfer capability means that, during most of the hours of the year, PJM used its high-cost generators to cover its internal demand, while it could have imported from MISO's lower-cost generators, thus decreasing both ISOs/RTOs production costs.

Figure 3.3 depicts the scale of impacts of zero-supply increased imports to PJM in its prices for the delivery years 2007/08 to 2014/15.

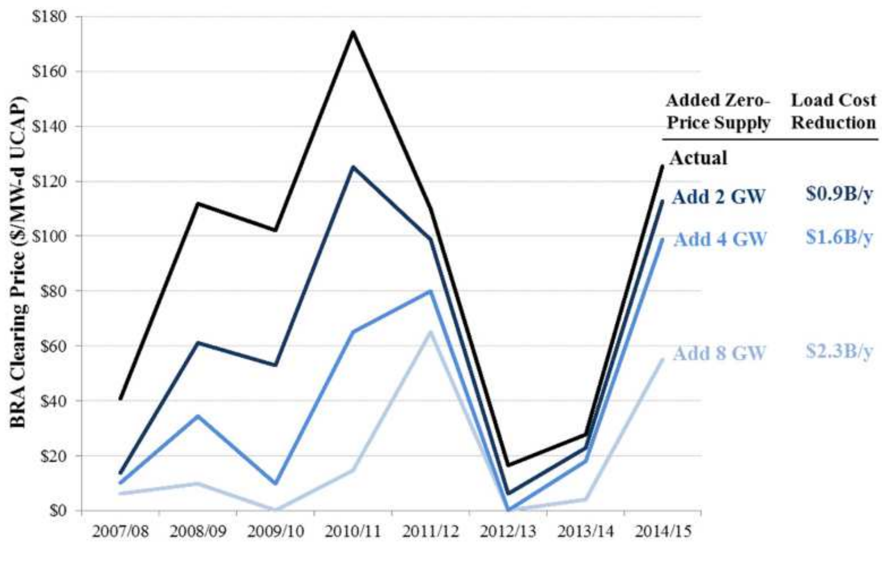

Figure 3.3- Impact of increased imports in PJM's prices[19]

[19] Source: https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Preliminary%20Brattle%20Report_MISO-PJM%20Capacity%20Seam%20Definition%20-%202011-12-06.pdf

As can be seen in Figure 3.3, the prices in PJM interconnection would have been deeply impacted by more efficiently scheduled sales. There is a great reduction in PJM's production costs, and therefore a great load cost reduction.

With a 4000 MW increase in imports from MISO, the ISO/RTO would have reduced its production costs by approximately $49 per MW-day ($18 per kW-year), which translates to a total load cost reduction of $1.6 billion per year, or $12 billion total.

3.4 Causes

As explained in the previous section, the large price differences between markets give a strong incentive for power to flow from MISO to PJM. Both ISOs/RTOs would benefit from these interchanges, as PJM would see their production costs reduced by importing lower-cost generation from MISO, and MISO generators would increase their benefit by selling power at a higher cost than their LMP.

This section focuses on why these transactions are not realized. The main reason why the interface is underutilized is the institutional barriers that the ISOs/RTOs impose on their market participants, which deter trade.

The most important of institutional barriers in the interface between MISO and PJM is firm transmission reservations. In order to be able to export power to PJM, MISO generators need to obtain a firm transmission path along the interface. This means obtaining a firm transmission path along the MISO lines, and another one along the PJM lines.

In recent years it has been observed that often market participants are not able to obtain said firm transmission paths along the interface, as these paths have already been reserved.

All or most of the capacity is unavailable due to previous reserves, although relatively little of it is used. These firm transmission rights have been granted to other market participants.

To solve the problem with the unavailability of transmission path it is necessary for both ISOs/RTOs to revise transmission rights awarded in the past and to create a new system for awarding firm service. However, this solution may lead to disadvantages for the current holders of firm transmission rights, who would have to be compensated in some other way.

Another institutional barrier that market participants have to face is the must-offer requirements. Both the Midwest ISO and PJM Interconnections require their market participants to make an offer into the day-ahead energy market in every hour. The purpose of this obligation is to guarantee that sufficient supplies will be available for every delivery hour.

However, these obligations create high risks and potential costs for sellers. Generators are required to make offers into the day-ahead market, based on the information that is available at that time. As price volatility is generally very high, the price difference between the two regions may change and even revert before the delivery hour starts. If this happens, the generator will have to face the settlements to account for the price difference between their offer and the real-time price difference between the ISOs/RTOs.

3.5 Solutions

Of all of the solutions that have been proposed to address inefficiencies at the seam between the Midwest ISO (MISO) and PJM Interconnections, two of them deserve special attention. Each of them can be associated with one of the solutions that were proposed in the NYISO-ISONE case study in the previous chapter.

The main difference between these two solutions is how market participants submit their offers to buy (export) or sell (import) power to the markets: individually or simultaneously to both markets.

3.5.1 Joint-ISO/RTO scheduled transactions

With this approach, each market participant submits their bids/offers at the individual markets [8]. This means that they submit two separate offers: one offer to “buy” at the exporting ISO/RTO, and another one to “sell” at the importing ISO/RTO.

The two ISOs/RTOs jointly determine the optimal tie-line schedule with the economic criterion of maximizing their benefits simultaneously. They then take corrective measures by comparing the deviation of the optimum interchange from the scheduled interchange. These measures include the scheduling of an incremental energy flow of such magnitude and direction that will bring the scheduled interchange as closely as possible to the optimum.

After this process, the information about the interchange is sent to the North American Electric Reliability Corporation (NERC) Interchange Distribution Calculator (IDC), where the data are stored.

The Joint-ISO/RTO scheduled transactions is similar to the tie optimization solution analyzed for the NYISO-ISONE case study, as market participants' offers are submitted separately to the individual markets.

3.5.2 Inter-regional dispatchable transactions

The novelty of this solution is that it proposes that market participants submit their bids/offers to both ISOs/RTOs simultaneously [8]. For this, a single common portal for submitting transactions would need to be created. This feature is similar to the coordinated transaction scheduling (CTS) solution considered in the previous chapter.

Each ISO/RTO applies their look-ahead Security Constrained Economic Dispatch (SCED), which produces an estimate of the prices at the border nodes for a specified quarter interval, taking into account the constraints of the interface. They trade this information with each other. In the next execution of the SCED each area selects its set of transactions that will be cleared (based on the economic criterion dictated by the SCED). The intersection of the two sets will be the transactions that will be finally cleared.

3.6 Conclusion

The Joint-ISO/RTO scheduled transactions approach would yield more efficient results. By determining the net tie schedule jointly, the ISOs/RTOs ensure that tie-line under-utilization and counter-intuitive flows do not happen at the time when the schedule is set, as tie optimization does.

By having a common portal through which the transactions can be submitted to both ISOs/RTOs simultaneously, the inter-regional dispatchable transactions approach would eliminate counter-intuitive flows, but not tie-line under-utilization, similarly to the coordinated transaction scheduling (CTS) case.

Any of these solutions would result in a more coordinated system than the current system. However, the joint-ISO/RTO schedule transactions approach is more advisable in terms of efficiency.

4. Loop flows

4.1 Description

Electricity does not necessarily flow through the “contract path” specified by the market participants when scheduling power. Instead, the actual electric power flows are determined by the generation and load patterns, the topology and the line impedances on the transmission network connecting generation to load. The deviation between the actual power flow (physical flow) and the scheduled flow is referred to as loop flow.

Loop flows are a natural consequence of having interconnected transmission systems, and the ISOs/RTOs should recognize them as such. However, loop flows may present operational challenges when their duration persists and their magnitude exceeds the anticipated levels.

The unscheduled flows move through a path that was not specified by the market participants when scheduling the transaction. They occupy transmission lines that belong to a region that was not scheduled to participate in the trade.

As this region already scheduled its own transactions with the objective of maximizing its transmission lines’ utilization, the unscheduled flows may cause these lines to reach congestion. They cause the lines to reach their maximum capacity, even though these lines could accommodate the nominal quantity scheduled to flow through them.

When this happens, loop flows may increase costs for generation and, ultimately, prices for consumers. Therefore, all the grid operators are interested in managing loop flows in order to minimize them.

Loop flows can be forward or counter-flow. Forward flows are in the direction of the congestion, which means that they contribute to the congestion. These flows are assessed charges. On the other hand, counter-flow loop flows are in the opposite direction of the congestion and they help relieve it.

4.2 Different cases

4.2.1 Lake Erie loop flows

Lake Erie loop flows are a perennial problem. This phenomenon is highly variable in nature, i.e. the direction and the magnitude of the flows might change even over the course of the day. Historically, the loop flows around Lake Erie have had an average counter-clockwise direction, as can be observed in Figure 4.1.

Figure 4.1- Lake Erie loop flow counter-clockwise direction[20]

However, during the first half of 2008, the New York Independent System Operator (NYISO) observed that the Lake Erie loop flows were increasing in magnitude and reversing direction (from counter-clockwise to clockwise) [9].

The main reason behind this change in the Lake Erie loop flows patterns was that a small group of market participants was scheduling exports of increasingly significant volumes of power from New York for import to Pennsylvania-New Jersey-Maryland Interconnection (PJM), through a "contract path" traversing the control areas of the Independent Electricity System Operator (IESO) and the Midwest Independent Transmission System Operator (MISO) rather than from the common interface between NYISO and PJM.

The key driver for this observed market behavior was the divergence of the locational marginal prices (LMPs) of the exporting and importing regions which resulted from the fact that the two

[20] Source: http://www.nyiso.com/public/webdocs/markets_operations/documents/ARCHIVE/white_papers/ARCHIVE/lerie_loopflow_report_11182008.pdf

areas involved in the transaction determine LMPs individually by applying different pricing rules, e.g. NYISO pays or charges external transactions based on the path over which the transaction is scheduled into or out of its control area while PJM prices them based on the source/sink of the transaction. Hence, PJM determines the settlement for New York energy based on the LMP at the common border of the two control areas without taking into account whether the transaction was scheduled to sink in PJM directly through its common interface with NYISO or through a circuitous path sourcing from NYISO and wheeling through IESO and MISO.

Due to the fact that the transmission facilities at NYISO's common border with PJM are located in a congested region of the New York Control Area (NYCA), LMPs are on average substantially higher compared to those at the NYISO's interconnection with the IESO where there is almost no transmission congestion (this disparity accentuated after mid 2007 NYISO improved the method it used to determine the price at its PJM border in order to take into account the west-to-east congestion constraints inside NYISO).

Consequently if the cost of scheduling energy through IESO and MISO to PJM is less than the difference between the LMPs at the NYISO's interconnections with PJM and IESO, it will be financially advantageous for a market participant to schedule transactions through the circuitous path across Lake Erie. Thus, the sellers in New York increase generation to serve the load in PJM as a result of the scheduling of external transactions through the circuitous path, but due to the fact that the actual electricity flows over the path of least resistance and as such approximately 80% of the power will flow to PJM through its common border with NYISO (clockwise direction) rather than traveling circuitously around Lake Erie (counter-clockwise direction).

This scheduling phenomenon exacerbates internal congestion and increases transmission costs at the New York Control Area (NYCA) as power flows in the clockwise direction entering NYCA from the IESO common border, flows through NYCA and finally sinks into PJM. It is estimated that during the period from January 1 to July 22, 2008 the total cost of circuital power schedules was $ 96 million and since the NYISO settlements are based on the contract paths and not the actual flows, the participants scheduled the circuitous transactions did not bear the full costs of the ramifications. Instead the cost was socialized among market participants and probably passed on to consumers [9].

In order to remedy the situation, NYISO (in the absence of adequate controls among the interconnected areas around Lake Erie) submitted an emergency filing to FERC on July 21, 2008 requiring permission to prohibit (from July 22) the scheduling of external transactions through eight circuital paths around Lake Erie. The paths that were banned are shown in Figure 4.2.

BANNED TRANSACTIONS

The following are the eight paths banned by the NYISO:

- NYISO to IESO to MISO to PJM
- NYISO to PJM to MISO to IESO
- IESO to MISO to PJM to NYISO
- PJM to MISO to IESO to NYISO
- PJM to NYISO to IESO to MISO
- MISO to IESO to NYISO to PJM
- MISO to PJM to NYISO to IESO
- IESO to NYISO to PJM to MISO

Participants in the New York wholesale electricity markets are no longer able to schedule transactions via these paths. Each precluded path has a corresponding direct path that may be used to move power between control areas in the region.

Figure 4.2- Transactions banned by NYISO to address the Lake Erie circulation issue[21]

With this measure, NYISO ensured that market participants scheduled their transactions through direct paths. In other words, this way NYISO made sure that all entities paid the costs of the transactions they scheduled, rather than passing a portion of those costs on to other market participants.

[21] Source : http://www.nyiso.com/public/webdocs/markets_operations/documents/ARCHIVE/white_papers/ARCHIVE/lerie_loopflow_report_11182008.pdf

The prohibition of these paths proved to be very efficient. On July 21 the average amount of loop flows was 457 MW in the clockwise direction. During the period from July 23 to August 31 the average amount of loops flows reduced to 121 MW in the counter-clockwise direction. In November 17, 2008 FERC orders the tariff revisions implemented by NYISO be made permanent [9].

4.2.2 Loop flows at the seam between MISO and PJM

The Northern Indiana Public Service Company (NIPSCO) has a significant number of transmission lines that lie at the seam between the Midwest ISO (MISO) and PJM Interconnections [10]. This often causes NIPSCO's transmission lines to be impacted by power flows scheduled between MISO and PJM.

NIPSCO has expressed to FERC its concerns about these loop flows. The main problem is that MISO and PJM schedule power to flow from one ISO/RTO to the other (usually from MISO to PJM, as the first generally has lower generation prices and can benefit from exporting to the second). Then, the two ISOs/RTOs agree on settlements to account for those transactions (PJM pays MISO for the marginal imported generation). However, an important part of the scheduled power did not flow through the direct path from MISO to PJM, but through NIPSCO's lines. And yet NIPSCO does not get paid for the use of its transmission lines, even when the unscheduled flows cause congestion.

Unscheduled flows through NIPSCO have both reliability and economic impacts. NIPSCO's lines were designed to comply with their scheduled transactions. But when they are affected by loop flows because of transactions scheduled by PJM and MISO, the lines may be congested, causing NIPSCO to be unable to deliver the demanded energy to its load. The economic impacts are a consequence of the costs incurred due to congestion.

It is important to resolve the issue of loop flows caused by the scheduling of transactions between MISO and PJM, both for the optimization of interchange between the two ISOs/RTOs and for the relief of NIPSCO's transmission lines.

The current approach to congested lines is market-to-market (M2M) redispatch [10]. This approach reallocates firm transmission capacity from one ISO/RTO to the other when the second ISO/RTO has an overload situation in one of its flowgates. Then, the second ISO/RTO pays a settlement to the first one as compensation for having relieved the congestion.

The M2M redispatch approach solves the congestion problem in the short-run. However, the settlement costs that the ISOs/RTOs have to incur by implementing this solution are very high.

The solution that has been proposed by NIPSCO in order to solve the issue in the long-run is a transmission upgrade of the grid. This way, the transmission lines would be able to accommodate the marginal transactions, without incurring congestion.

The ISOs/RTOs would need to share the necessary information to determine the total costs that are incurred in the M2M process (each ISO/RTO would have to compute the settlement payments received minus the settlement payments made), and compare them to the total cost of a transmission upgrade.

The costs of the upgrade should be allocated per the benefits evaluated [10]. This means that the ISO/RTO that is expected to be the most benefited by the transmission upgrade should be the one to pay more for its implementation.

NIPSCO has repeatedly expressed to FERC its worries about the lack of coordination of MISO and PJM to resolve loop flows. NIPSCO asked FERC to take the matter into its own hands, as it had not seen any progress on the issue.

4.3 Solutions

The current approach to addressing loop flows is transmission loading relief (TLR), which involves the curtailment of transactions when they are causing congestion in a line [11].

As addressed in the previous sections, ISOs/RTOs have been working on minimizing and managing loop flows for years. They have already adopted several measures, such as market-to-market (M2M) redispatch (in the case of MISO and PJM) or the prohibition of circuitous path (in the case of the Lake Erie loop flows, by the New York ISO).

This section focuses on the solutions that may have to be introduced to manage the issues that are caused by unscheduled flows.

4.3.1 Physical solutions

The best physical solution to loop flows is the installation of phase angle regulators (PARs) in the transmission lines [11]. PARs are electro-mechanical devices that can be used to change the impedance of the system. They are able to redirect power to flow through the scheduled path. This provides a way to manage loop flows, and avoid one entity taking advantage of the services provided by another.

PARs started to be installed in the interconnection between Michigan and Ontario in 1999, to control the Lake Erie circulation, but several technical issues and equipment failure have delayed their operation.

A drawback to the use of phase angle regulators is that they are installed to solve a very specific operational need, and they usually work very well for that purpose. But as system conditions change very frequently, PARs may be needed to perform another task, and they are very difficult to redirect towards another purpose. Furthermore, there are limitations to how much power can be controlled by a PAR.

There are other physical solutions that can be used to address loop flows, such as variable frequency transformers or series capacitors. However, phase angle regulators provide the best opportunity to solve the issue.

4.3.2 Market-based solutions

An interesting market-based solution is the buy-through of congestion (BTC) process [11]. This method provides a way to manage congestion, transferring the costs of congestion to the entity scheduling the transaction and thus avoiding some entities taking advantage of the services provided by others.

When scheduling a transaction, a market participant would indicate if it is willing to pay the possible congestion charges that the transaction may cause (WBT), or if it is not willing to pay them (NBT). WBT transactions will be given priority over NBT transactions when there is congestion and some transactions have to be curtailed in order to relieve it.

When this happens, NBT transactions will be the first ones to be curtailed. WBT transactions will only be curtailed if all of the NBT transactions have already been curtailed and the congestion has not yet been relieved.

Once the congestion issue is solved, WBT transactions will be the first to go back to normal, and NBT will only be reinstated once every WBT is working.

Stakeholders have expressed the need for the buy-through of congestion (BTC) process to add the possibility to specify an “up-to” congestion charge limitation. This means that the scheduling party could specify a maximum cost it is willing to pay (WBT). If the transaction incurs a cost that is higher than that “up-to” level, then the transaction would become NBT.

Indeed, the decision for an entity on whether or not it is willing to buy-through may depend on the level of payment it would have to afford. If that payment is higher than the revenue it expects to receive for that specific transaction, then it will probably not be willing to buy-through (NBT).

4.4 Conclusion

Loop flows present an important issue that needs to be addressed and which requires coordination between ISOs/RTOs. As it is an issue that affects multiple regions- not just the regions scheduling the transaction- they need every ISO/RTO involved to work to resolve it.

It is very difficult to analyze the impact of loop flows, since they are caused by transactions that were not scheduled to flow through the path they are loading. That is why loop flows are so difficult to address.

The ISOs/RTOs should implement a solution that involves both physical and market-based components, to achieve the maximum possible outcome. It is also essential that the ISOs/RTOs take into account the impact that their unscheduled flows have in other markets, and compensate them accordingly.

This is especially important in the MISO-PJM loop flows case, where NIPSCO has serious impacts in their transmission lines due to their transactions. The ISOs/RTOs should reach an agreement that also involves NIPSCO, and compensate them for the impacts they may cause.

The most important thing is that an agreement is reached and that the ISOs/RTOs work jointly to comply with it.

5. Simulation

1.1 Objective

As discussed in chapter 4, loop flows represent a major seams issue for the ISOs/RTOs. When a transaction is scheduled to flow from A to B, a part of it will flow through the direct path that connects these two points. But another part (sometimes a very significant amount of MW) will flow through an unscheduled path, and can sometimes cause congestion in the lines that belong to entities that did not schedule the transaction.

The objective of this simulation is to apply the knowledge that has been learned about the United States to a case in central Europe. A three-bus system is modeled, in order to identify loop flows and their effects (negative, but also positive in some cases). Each of the buses represents a country in central Europe: France, Italy and Switzerland. In this case, the three countries are all connected to each other. Therefore, there will be three transmission lines, connecting every bus to each other.

First, several assumptions will be made regarding the system: initial generation and demand at each bus (country), transmission line limits and transmission line reactance. Then a set of bilateral transactions will be considered. For each transaction we will calculate the loop flows and their effect in the transmission lines. This three-bus system is a simple model of what could be extrapolated to a larger system consisting of different interconnected countries.

The three-bus system model is illustrated in Figure 5.1. As can be seen, bus 1, bus 2 and bus 3 correspond to France, Italy and Switzerland, respectively.

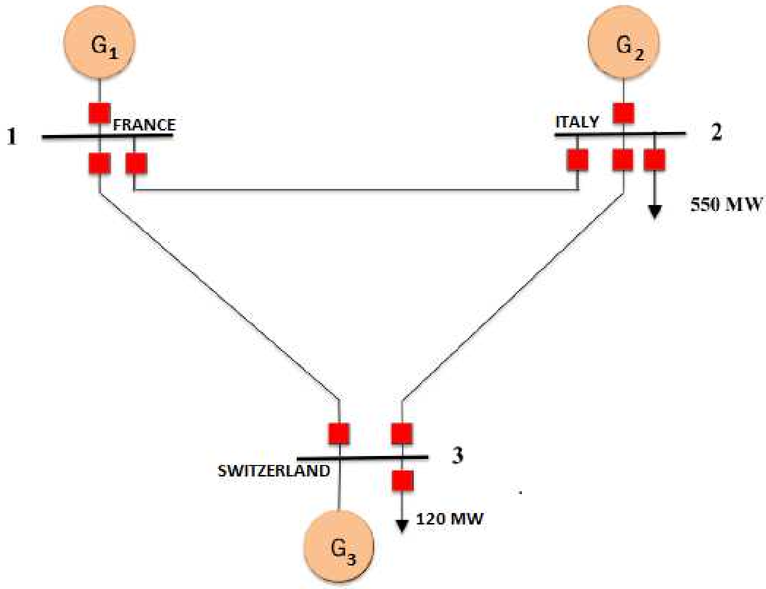

Figure 5.1- Three-bus system for the simulation

5.2 Data for the system

The assumptions regarding the characteristics of each transmission line are illustrated below in Table 5.1.

Transmission Line number	From bus	To bus	Reactance (p.u.)	Maximum flow (MW)
1	1	2	0.1	300
2	1	3	0.125	250
3	2	3	0.2	200

Table 5.1- Transmission lines characteristics

It is essential to pay attention to the way that the transmission lines are defined. For example, line 3 is defined as going from bus 2 to bus 3. This means that when the flows are calculated, a positive flow would mean that power is flowing from bus 2 to bus 3, whereas a negative flow would mean that power is flowing in the opposite direction.

The initial generation and demand of each bus (country) is illustrated in Table 5.2.

Bus Number	Initial Generation (MW)	Initial Demand (MW)
1 (reference)	193.1698	-
2	354.6038	550
3	122.2264	120

Table 5.3- Initial Power Generation and Demand

5.3 Methodology

First, the initial flow through each line will be calculated. For this, the DC power flow method described in [12] will be implemented in a Mat lab code.

Then, several bilateral transactions will be evaluated in terms of loop flows. For this, the Power Transfer Distribution Factor (PTDF) [13] will be calculated for each transaction. This factor gives the amount of MW that flow through the line that directly connects the buses, and also how much of it flows through the rest of the lines in the network, i.e., loop flows.

A bilateral transaction of power between two buses means that the generation in the selling bus increases, while the demand in the buying bus increases. For example, if 20 MW of power are transferred from France to Italy, then France's generation will increase by 20 MW, and Italy's demand will increase by the same amount.

5.3.1 DC Power Flow Method Implementation

The DC Power Flow Method is used in this chapter to find the amount of power that flows through each transmission line in each case.

Let a system be composed of N nodes (buses) and L lines (in our simulation case, N=3 and L=3). Let P denote the Nx1 vector of active power injected in each bus of the system (that is power generation minus power demand). Let θ denote the Nx1 vector of nodal phase angles. Then

$$P = B \cdot \theta \rightarrow \theta = B^{-1} \cdot P \qquad (1)$$

Where the off-diagonal element of the B matrix represents the susceptance (which is the inverse of the reactance) of the branch connecting buses i+1 and j+1 and the diagonal element is the sum of all the row elements multiplied by -1.

The real power flow through each transmission line in the network is given by the Lx1 vector f:

$$f = D \cdot A \cdot \theta \qquad (2)$$

A is the LxN incidence matrix that determines the direction of each line. The component j of line i is non-zero whenever line i is coincident with node j. This matrix represents the “from” bus with +1 and the “to” bus with -1.

D is the LxL diagonal matrix that has the susceptance of each line.

$$f = D \cdot A \cdot B^{-1} \cdot P \qquad (3)$$

Let $H = D \cdot A \cdot B^{-1}$, so that we can rewrite (3) as

$$f = H \cdot P \qquad (4)$$

In our three-bus system, matrixes A, D and B are defined as follows:

$$A = \begin{bmatrix} 1 & -1 & 0 \\ 1 & 0 & -1 \\ 0 & 1 & -1 \end{bmatrix} \qquad D = \begin{bmatrix} 10 & 0 & 0 \\ 0 & 8 & 0 \\ 0 & 0 & 5 \end{bmatrix} \qquad B = \begin{bmatrix} 18 & -10 & -8 \\ -10 & 15 & -5 \\ -8 & -5 & 13 \end{bmatrix}$$

To calculate the f vector, the DC power flow removes the line and column of the B matrix that correspond to the slack bus. The same is done with the column corresponding to the slack bus in matrix A. In our case, the slack bus is country 1. Therefore, the simulation will use matrixes A_{red} and B_{red}.

$$A_{red} = \begin{bmatrix} -1 & 0 \\ 0 & -1 \\ 1 & -1 \end{bmatrix} \qquad B_{red} = \begin{bmatrix} 15 & -5 \\ -5 & 13 \end{bmatrix}$$

5.3.2 PTDF Calculation

The Power Transfer Distribution Factor gives the amount of MW of a transaction that flow through each transmission line. For example, for a transaction of 20 MW that is scheduled to flow from bus 2 to bus 3: the direct path that connects these two buses is line 3. The PTDF will give the amount of these 20 MW that will flow through line 3, but also the amount that will flow through lines 1 and 2.

The PTDF is very useful to evaluate loop flows in an interconnected network. This fact directly gives the percentage of a transaction that will become loop flows.

The PTDF is calculated using the H matrix that was also used for the implementation of the DC Power Flow method. This matrix is called the Injection Shift Factor (ISF) matrix.

A transaction can be denoted as $\mathrm{w} = \{\mathrm{t}, \mathrm{s}, \mathrm{b}\}$, where t is the amount of MW transferred, s is the exporting or "selling" bus and b the importing or "buying" bus.

The ISF matrix has L rows and N columns. For a given transaction w, the PTDF can be calculated as

$$PTDF_l^w = H_l^s - H_l^b \quad (5)$$

5.4 Evaluation of transactions and Results

To evaluate the effect of loop flows in our three-bus system, we will take sets of bilateral transactions, calculate the flow through each line and the PTDF associated to each transaction. We will then assess whether or not a transaction is risky, in terms of its PTDF and the flows compared to each line's maximum flow.

For each bilateral transaction, we will consider two cases, so that each country will take the role of importing and exporting bus.

Figure 5.2 illustrates what the system looks like before any transactions are considered and the generation, demand and line flows are altered.

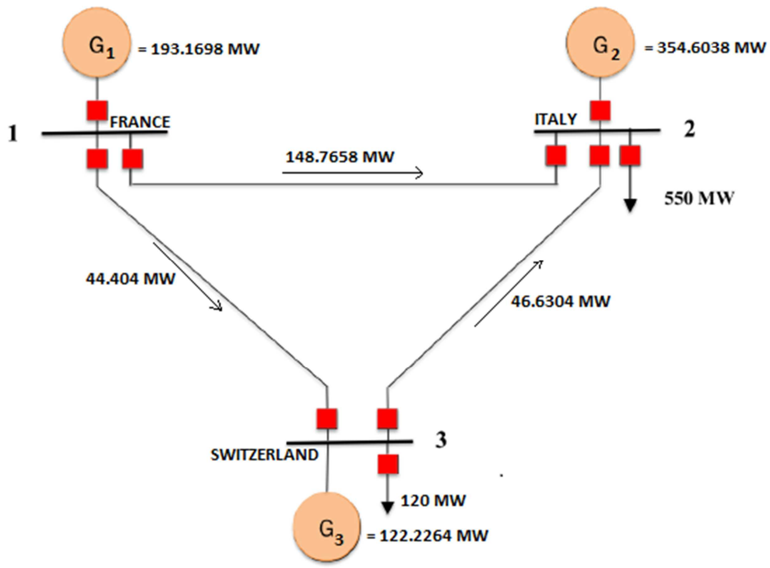

Figure 5.2- Initial conditions of the system

5.4.1 Transactions between Italy (bus 2) and Switzerland (bus 3)

<u>CASE A</u>: Italy sells at Switzerland

We will denote each transaction with w= {t, 2, 3}, since s=2 (selling country) and s=3 (buying country).

Running Programs 1 and 2 in Appendix B we obtain the flow through each line, its change with incremental amounts of power (Figure 5.3) and the PTDF.

We can analyze the effect of the transaction by observing Figure 5.3. Initially, the transaction increases power flow through line 2. However, with increasing amounts of MWs, there comes a time when all three flows increase. It must be taken into account that this particular flow "should" be flowing only through line 3 as it was scheduled. Every MW of increasing flow through lines 1 and 2 represent loop flows.

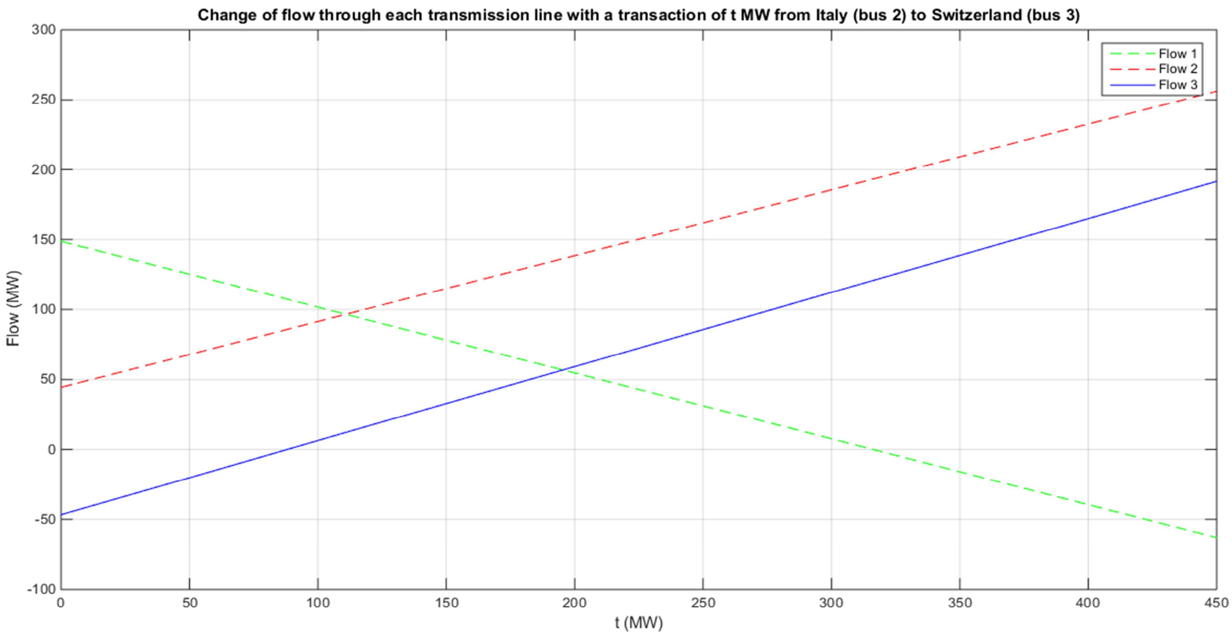

Figure 5.3- Change of flow through each line with transactions of t MW from Italy to Switzerland

As can be seen, line 2 is finally congested (it reaches its maximum flow, 250 MW) at approximately t=450 MW. Therefore, the transaction causes congestion in a line that it was not scheduled to flow through. This is one of the main concerns with loop flows, as bus 1 (France) would be affected by this congestion even though it took no part in the scheduling.

It is clear that an important amount of t is flowing through the circuitous path (Italy-France-Switzerland). The PTDF gives exactly that amount. The PTDF of lines 1 and 2 for this transaction is 0.4706. This means that more than 47% of the power is flowing through an indirect path, increasing the levels of flows and causing high risks for congestion.

<u>CASE B</u>: Switzerland sells at Italy

In this case, the transactions are denoted with w= {t, 3, 2}. It can be observed in Figure 5.4 that line 3 is the first one to reach congestion (200 MW), at approximately t=300 MW. In this case, the first line to reach its maximum flow is also the direct path of the transaction, so it does not affect non-scheduling entities as much as case A. However, at t=300 MW, the flow through line 1 is almost its maximum. This means that if bus 1 (France) were to schedule some transactions through line 1, it would be congested very rapidly.

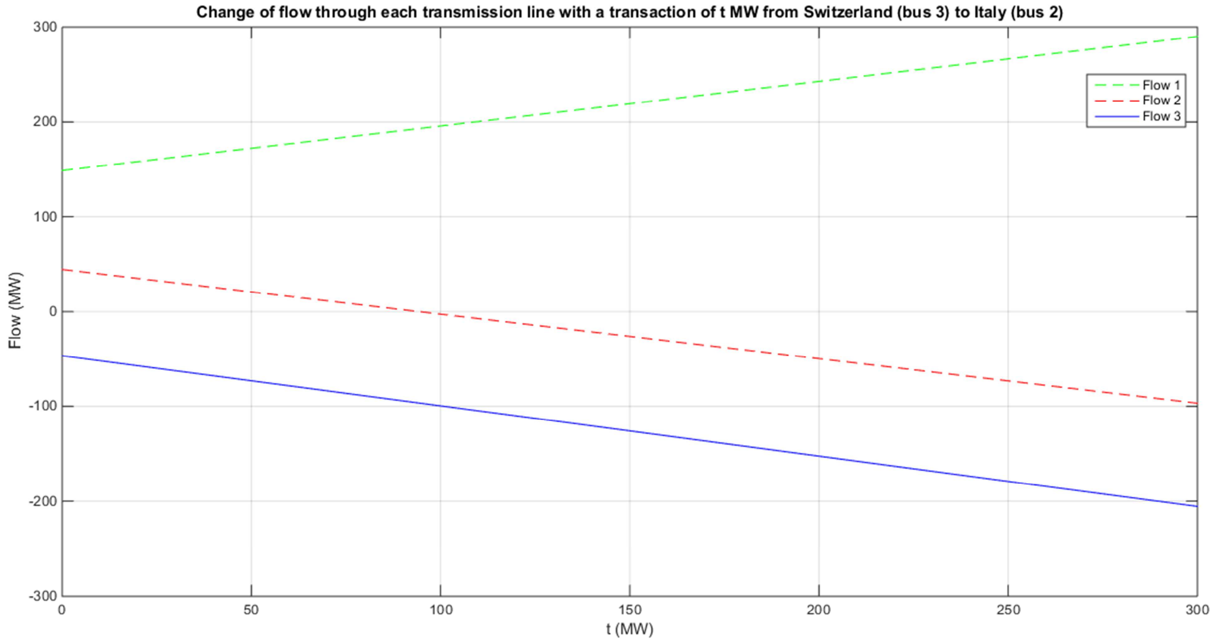

Figure 5.4- Change of flow through each line with transactions of t MW from Switzerland to Italy

The PTDF is here the same as in CASE A, as the selling and buying country remain the same, only inverted. Therefore loop flows here also represent more than 47% of the power is flowing in through the wrong path.

5.4.2 Transactions between France (bus 1) and Italy (bus 2)

CASE A: France sells at Italy

The transaction of t MWs from bus 1 to bus 2, from the beginning tends to saturate all three lines of the system. In the last section (transactions between buses 2 and 3) we observed that, for small amounts of power, loop flows could sometimes help relieve congestion, when flowing in the opposite direction of the initial flow. However, here all three flows go in the same direction as the initial flows. Therefore these transactions, denoted as w= { t , 1, 2 } are specially risky for the system.

The increasing flows through each transmission line are illustrated in Figure 5.5. It can be observed that the first line to be congested is line 1, which connects France and Italy. This means that congestion does not affect, in this case, the lines that the transaction was not scheduled to flow through.

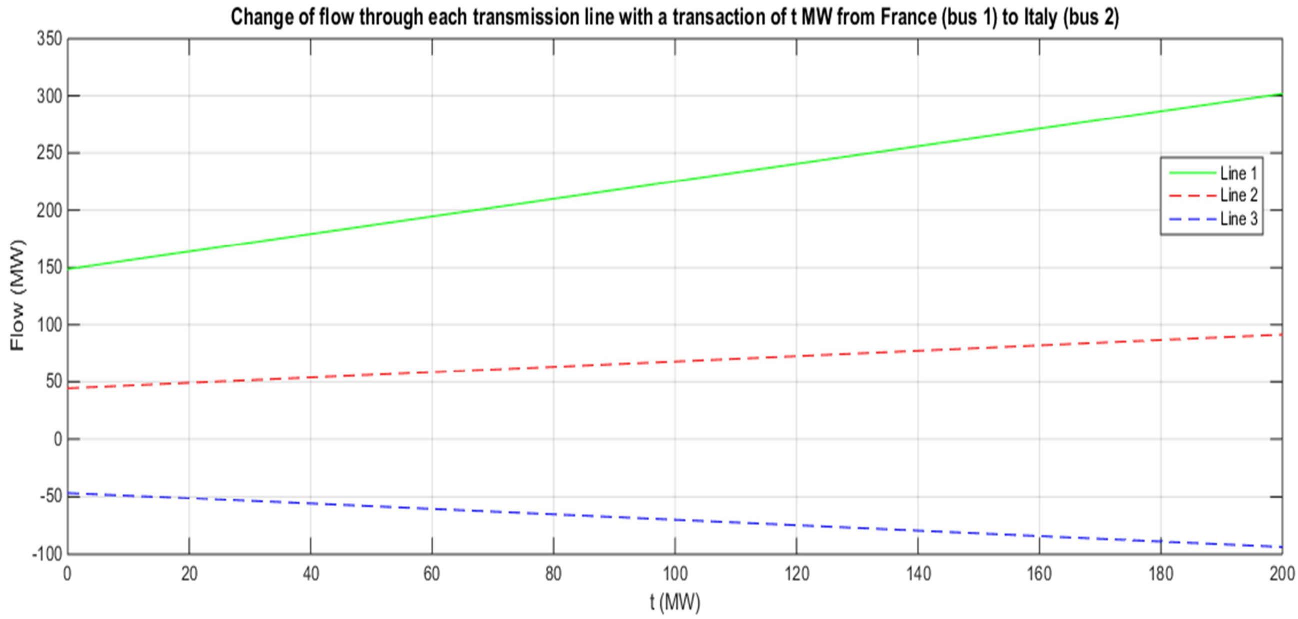

Figure 5.5- Change of flow through each line with transactions of t MW from France to Italy

Let us now look at the PTDF of this set of transactions. In this case, the PTDF for line 1 (France-Italy) is 0.7647, which means that 76.47% of the transaction flows through this line. Therefore, the most important amount of MWs flow through the right path, and this is why line 1 is the first to reach congestion, at approximately t=200 MW.

<u>CASE B</u>: Italy sells at France

In this case, initially, all flows are reduced, since the incremental flows that these transactions cause, flow in the opposite direction as the initial flows. Therefore, for small amounts, transactions from Italy to France actually help to relieve congestion in all three transmission lines of the system.

This is something that is not usually considered about loop flows, as they are often seen as a problem that needs to be solved. But as can be seen in this case (Figure 5.6), loop flows can also be beneficial to the network. However, as the amount of MWs scheduled increases, loop flows cause the flow through the lines to reverse and, ultimately, increase, causing congestion.

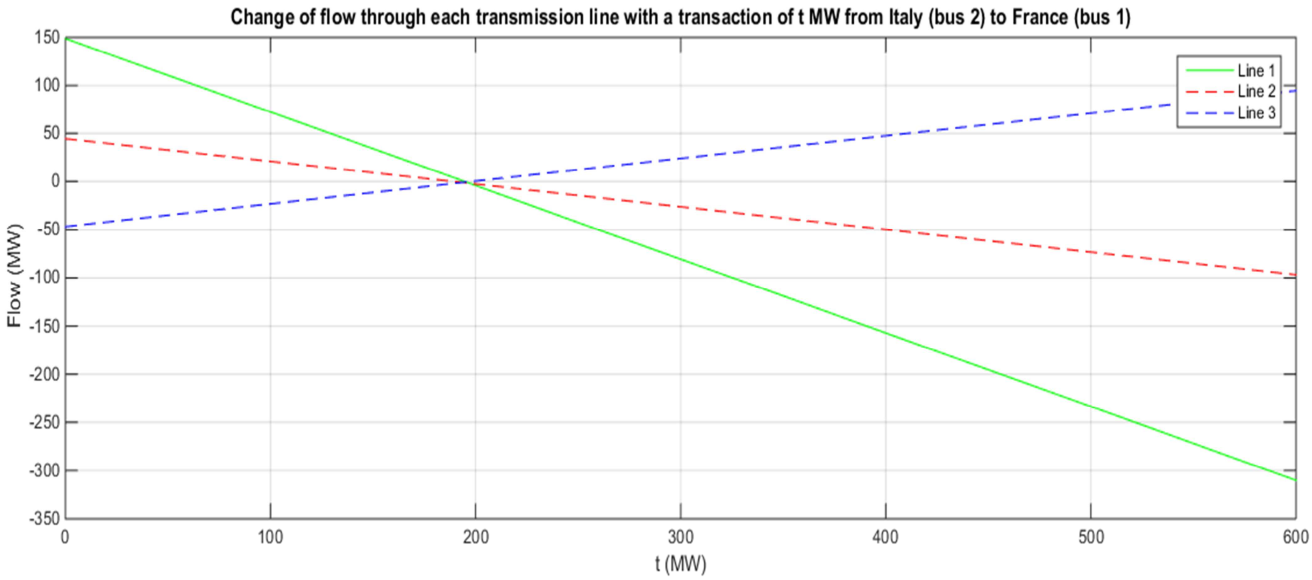

Figure 5.6- Change of flow through each line with transactions of t MW from Italy to France

5.4.3 Transactions between France (bus 1) and Switzerland (bus 3)

CASE A: France sells at Switzerland

As can be observed in Figure 5.7, transactions from France to Switzerland initially cause the flows through lines 1 and 2 to increase. The flow through line 3 is initially reduced, but it is soon reversed (at only t=150 MW), and after this it starts increasing as well. The first line to reach its maximum flow is line 2, which is the direct path that connects France and Switzerland. The PTDF for line 2 is approximately 0.71, which means that 71% of the power flow through the right line, while 29% flow through a circuitous path (France-Italy-Switzerland).

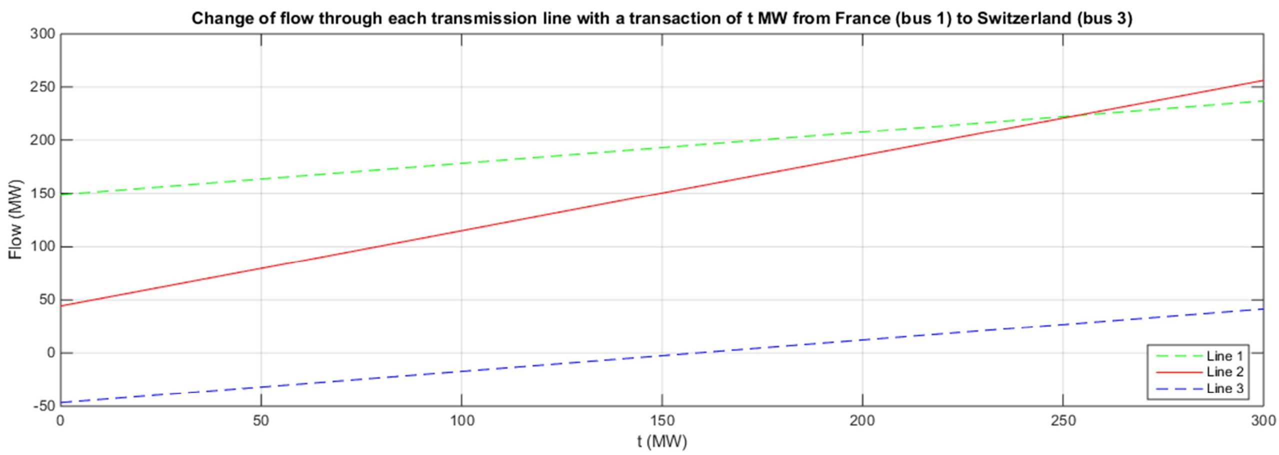

Figure 5.7- Change of flow through each line with transactions of t MW from France to Switzerland

CASE B: Switzerland sells at France

Comparably as in case A, transactions from Switzerland to France soon tend to flow through the same direction as the initial flows, thus increasing the power through each line and finally causing congestion. In this case the first line to reach its maximum flow is also line 2, which is the one that directly connects the two buses that take part in the transaction.

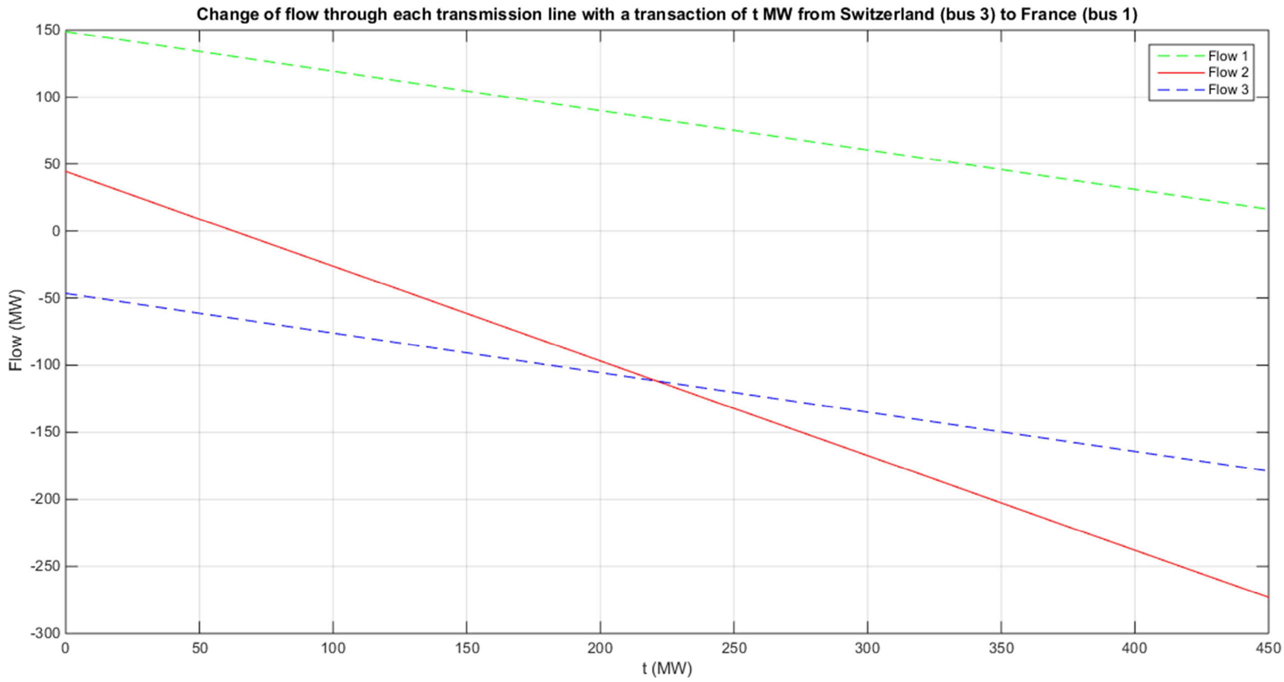

Figure 5.8- Change of flow through each line with transactions of t MW from Switzerland to France

6. Conclusion

From our previous discussion, we have identified three major seams issues which are tie-line underutilization, counter-intuitive flows and loop flows.

We have defined that tie-line underutilization occurs when the number of MW scheduled to flow from one area to the other do not reach the line's total capacity and thus impeding price convergence between the two regions involved in the transaction. This means that there is still remaining tie-line capacity that could be used to send additional power from the low-cost region to the high-cost region and consequently reducing the price disparity between them.

Counter-intuitive flows occur when power flows in the economically disadvantageous direction (from the high-cost region to the low-cost region). There are two possible cases. The first case is when power is scheduled to flow in the right direction, but the amount of MW scheduled exceeds the optimum. In this case, a part of the MW will be flowing in the right direction, but after the optimum is reached the prices of the ISOs/RTOs invert (the high-cost region becomes the low-cost region), which means that the economically advantageous direction changes. Therefore, the last MWs are flowing in the wrong direction, and high-cost generation is being dispatched when demand could be met at a lower price.

The second case of counter-intuitive flows is when power is scheduled to flow in the wrong direction. This can happen due to price volatility, as a transaction may be optimal when it is scheduled, but the conditions may change when it is executed.

Loop flows are a result of the interconnected system. Electricity does not necessarily flow through the "contract path" specified by the market participants when scheduling power transactions. Instead, the actual electric power flows are determined by the generation and load patterns, the topology and the line impedances on the transmission network connecting generation to load. Loop flows are unscheduled power which represents the difference between the scheduled flow and the physical flow in the transmission lines. Loop flows may present operational challenges when their duration persists and their magnitude exceeds the anticipated levels.

Among the many causes for seams issues, some require important attention. One of the main problems is the lack of coordination between the ISOs/RTOs when setting the net tie scheduled. Different markets have different rules and procedures that differ greatly from neighboring regions. These differences result in each ISO/RTO having different methods and approaches to set the net tie scheduled, different requirements for market participants, and other discrepancies that deter external interchanges.

Another important cause for seams inefficiencies is the large time delay between the moment when a transaction to import or to export energy is accepted by the ISOs/RTOs and when the power actually flows. This involves important financial risks for market participants, as the system conditions change greatly over the course of an hour (prices depend on factors such as weather conditions, economic conditions and availability of supply).

Institutional barriers represent another cause for seams issues. Each ISO/RTO imposes several charges on external transactions, which act on detriment of an efficient interchange. Also, it is hard for market participants to obtain firm transmission rights to schedule power trade, as most of these firm rights have already been granted but are not in use.

The ISOs/RTOs have acknowledged the importance of seams issues and have been working to resolve them. The main effort has been towards collaboration: most ISOs/RTOs have signed agreements with their neighboring ISOs/RTOs, committing to improve coordination between regions and to eliminate some of the institutional barriers that deter trade.

For future efforts, the best thing to resolve tie-line issues would be to harmonize the markets so they become more uniform in terms of their rules. In the future, it would be very beneficial to design a unified market under one ISO/RTO and dispatching the multiple areas as one single area. This would mean merging the ISOs/RTOs. This would result immediately in the optimum scheduling of the tie-line, because the tie-line would be dispatched as any other internal transmission component of the unified transmission network.

As for loop flows, the best solution to deal with them in the long-run would be to upgrade the transmission grid. This way, the transmission lines would be able to accommodate the marginal transactions, without incurring congestion costs.

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Appendix A. Acronym list

ATC	Available Transfer Capability
BTC	Buy-Through Congestion
CEL	Capacity Export Limit
CETL	Capacity Emergency Transfer Limit
CIL	Capacity Import Limit
ComEd	Commonwealth Edison
CTS	Coordinated Transaction Scheduling
FERC	Federal Energy Regulatory Commission
HFS	High Frequency Scheduling
IDC	Interchange Distribution Calculator
IESO	Independent Electricity System Operator
ISO	Independent System Operator
ISO-NE	Independent System Operator- New England
LMP	Locational Marginal Price
M2M	Market-to-Market
MISO	Midwest Independent System Operator
MP	Market Participant
NBT	Not willing to Buy-Through
NEPOOL	New England Power Pool
NERC	North American Electricity Reliability Corporation
NIPSCO	Northern Indiana Public Service Company

NYCA	New York Control Area
NYISO	New York Independent System Operator
NYN	New York North interface
OPEC	Organization of the Petroleum Exporting Countries
PAR	Phase Angle Regulator
PJM	Pennsylvania-New Jersey-Maryland interconnection
PTDF	Power Transfer Distribution Factor
RT	Real Time
RTO	Regional Transmission Operator
SCED	Security Constrained Economic Dispatch
TLR	Transmission Loading Relief
TTC	Total Transfer Capability
UCAP	Unforced Capability
WBT	Willing to Buy-Through

Appendix B. Mat lab code

Program 1

Program 1 initializes the system and calculates the initial flow through each transmission line. It then calculates the flows with a chosen bilateral transaction (in this case, 100 MW from bus 2 to bus 3) and calculates the PTDF associated to this transaction.

```
clear, clc;

A = [ -1, 1, 0; -1, 0, 1; 0, -1, 1];
D = [ 10, 0, 0; 0, 8, 0; 0, 0, 5];
B = [ 18, -10, -8; -10, 15, -5; -8, -5, 13];
Bred = [ 15, -5; -5, 13];
Ared = [-1, 0; 0, -1; 1, -1];
H = D * Ared * inv(Bred);
Pg2_0 = 354.6038;
Pd2_0 = 550;
Pg3_0 = 122.2264;
Pd3_0 = 120 ;

P2_0 = Pg2_0 - Pd2_0;
P3_0 = Pg3_0 - Pd3_0;

f_0 = H * [P2_0 ; P3_0];

Pg1_0 = f_0(1,1) + f_0(2,1);
Pd1_0 = 0;
P1_0 = Pg1_0 - Pd1_0;

Pg1 = Pg1_0;
Pd1 = Pd1_0;
Pg2 = Pg2_0;
Pd2 = Pd2_0;
Pg3 = Pg3_0;
Pd3 = Pd3_0;

% Data of the transaction

t=100;
s=2;
b=3;

if (s==1)
    Pg1=Pg1+ t
end


if  (s==2)
    Pg2=Pg2+ t
```

```
end

if (s==3)
    Pg3=Pg3 + t;
end

if (b==1)
    Pd1=Pd1 + t;
end

if (b==2)
    Pd2=Pd2 + t;
end

if (b==3)
    Pd3=Pd3 + t;
end

% Calculation of flows with the new transaction

P1 = Pg1 - Pd1;
P2 = Pg2 - Pd2;
P3 = Pg3 - Pd3;

f= H * [ P2 ; P3];

% Power Transfer Distribution Factors (percent of the transaction that flows
% through each line)

PTDF_1 = H(1,s-1) - H(1,b-1);
PTDF_2 = H(2,s-1) - H(2,b-1);
PTDF_3 = H(3,s-1) - H(3,b-1);

% Incremental Flows (number of MW of transaction t
% that flow through each line)

IF_1= PTDF_1 * t;
IF_2= PTDF_2 * t;
IF_33= PTDF_3 * t;
```

Program 2

Program 2 obtains the plots that represent the change of flow through each transmission line with a transaction of t MW, in this case from Italy to Switzerland. The direct path for this transaction is transmission line 3. The program represents the unscheduled path (lines 1 and 2) with dotted lines.

```
% country 2 (Italy) sells at country 3 (Switzerland)
% the direct path is line 3

t=[0 50 450];

f1=[148.7658 125.2364 -62.9989];
f2=[44.404 67.9334 256.1687];
f3=[-46.6304 -20.1598 191.6049];

plot(t,f1,'--g')
hold on

plot(t,f2,'--r')
hold on

plot(t,f3,'b')
hold on

title('Change of flow through each transmission line with a transaction of t
MW from Italy (bus 2) to Switzerland (bus 3)')
xlabel('t (MW)')
ylabel('Flow (MW)')
legend('Flow 1','Flow 2','Flow 3')

grid on
```