Case Study – Managing reliability in a market

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Why?

The prospect of significant uptake of DER heralds a world the distribution network will host a diverse set of ‘participants’ that own passive or active DER, and demand response.

This gives rise to substantial uncertainty about the nature of power flows and voltage on the distribution network (and potentially through to the transmission grid), which has security and reliability implications (depending on the degree to which autonomy and devolution of control to DER owners).

The question we wish to address is: **what it the most efficient way to coordinate DER to manage reliability?**

We propose that the history of the evolution of the NZ wholesale electricity market offers an insightful case study, which illuminates that:

1. Electricity markets - with a diverse set of participants, acting in their own commercial interest - can be designed to deliver the desired level of security and reliability

2. They do this by combining

   a. a level-playing-field market with transparent SRMC-based pricing based on economic dispatch, and

   b. a framework for security which includes constraints on economic dispatch, and coordinating system operation policies and procedures which have, as their principal objective, the avoidance of ‘cascade failure’

Questions to keep in mind

As we discuss the evolution of the wholesale market for the transmission grid, it is worthwhile considering:

1. Is the economic framework for “efficient operation” (i.e., minimise short-run cost) any different on the distribution network than it was for the wholesale market?
2. How critical do you think the role of dynamic, transparent, locational-based pricing, as a mechanism to incentivise and coordinate the actions of DER/DR (or DER/DR aggregators), is?
3. How does all this link to long-run investment incentives of distributors and DER owners?
4. Are the variables/limitations/constraints that drive security and reliability any different on the distribution network?
5. What would a “system operator” on the distribution network look like? And what is the minimum necessary linkage between a distribution system operator and the transmission system operator? Is it just a big old forecasting job?
6. Offer and centralised dispatch makes complete sense on a grid with market participants who each individually can have a significant national impact, but also are in the business of generating electricity and thus have teams of people dedicated to interacting with the market. Is the aggregator the analogous participant on the distribution network, and what does this mean for market evolution?

Reliability amidst Competition – a case study

The development of the New Zealand Electricity Market (NZEM) charts the evolution of system control, pricing and competition.

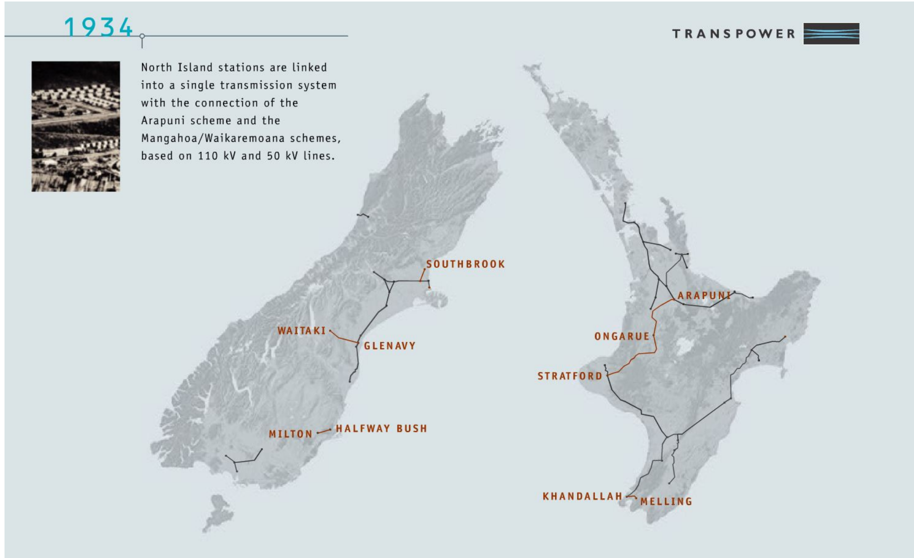
We will follow two strands initially:

- System Operation
- Pricing

Concerns over pricing – and also the management of system security – led to the reforms of the 1990s, which saw a new wholesale market established, which fused security and reliability requirements together with competition.

This model, which was seen as world leading at the time, has been operating successfully for over 20 years.

Maintaining Security and Reliability on the grid



"System Operation" predates the market: "operators" emerged in the 1940s as communications (and the development of an interconnected system) allowed – and necessitated - coordination between different parts of the country.

South Island's first "load dispatch" station in Christchurch (1942) allowed Addington staff to liaise with operators at Waitaki and Coleridge.

This gives us a hint as to what a key role of "operation" (or "system control") was – coordination between demand and supply, the latter being more discretionary.

System Operation in 1970s

Functions of the control centres 1973

LOAD CONTROL

1. Load allocation
   - Matching total generation to load.
   - Monitoring the amount of water used by each hydro power station.
   - Controlling the interchange of energy between the North and South Islands.
2. Security monitoring
   - Ensuring sufficient reserve generation was available to meet unexpected contingencies.
3. Voltage control
   - Ensuring that voltages in all parts of the system were within required limits, and were appropriate for managing transmission losses and for the stable operation of generating plant.
4. Water management
   - Controlling water flows at control gates and spillways under normal and flood conditions.

SWITCHING CONTROL

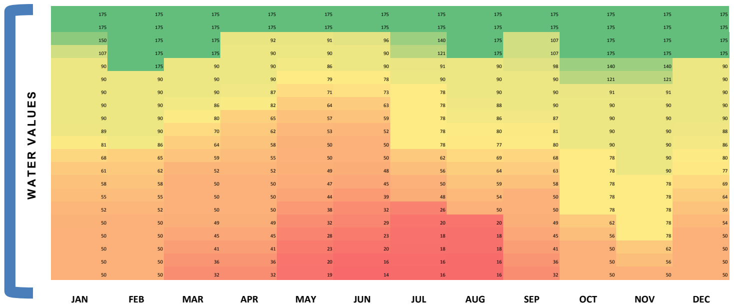
1. Main grid switching
   - Issuing instructions for release of equipment for work.
   - Directing restorative action following automatic fault disconnection.
2. Security monitoring
   - Monitoring network loading to avoid overloads, shedding and restoration of load as necessary in emergencies.
3. Logging of data and events
   - Log-keeping as required for load control.

Control centres in the 1970s were matching generation to load, and managing the water in hydro reservoirs, as well as managing system stability and security (voltage, reserves) and “operating” the grid (switching for maintenance etc).

The matching of generation to load and control of hydro reservoirs was actually an economic decision, but it wasn’t necessarily always seen this way (especially hydro). In the late 1970s, academic research (pioneered in NZ and South America) led to “reservoir guidelines” (which ultimately led to the notion of “water values”) which helped operators decide how much to release at any point in time. These guidelines were based on the cost of operating thermal plant (coal, oil etc).

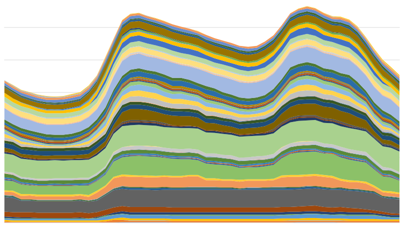
System Operation in 1980s

Medium term - water value optimisation (Prism/Spectra)



Short term – Merit Order to PC-Schn scheduling tool

WHK $200
SFD $60
WKA $50
HLY $45
SI HYD $35
WKO $20



Real-time – real-time schedule, Reserve Management Tool and Operator experience

WHK 0MW
SFD 0MW
WKA 6MW
HLY 300MW
SI HYD 600MW
WKO 800MW

Over the late 1970s and 1980s optimisation models were increasingly used to determine "dispatch" – the process of matching generation to load. These models had the objective of minimising the cost of generating from thermal plants (and shortage costs), and made greater use of the "water value" concept to value hydro.

The management of hydro reservoirs meant that NZ's system operation had a medium-term aspect – system security wasn't just what can be generated right now, but what may or may not be able to be generated in 3 months' time.

So system operation had a number of dimensions:

- Real time (right now)
- Short term (next few hours and days, or "scheduling")
- Medium term (next few months reservoir management)

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System Operation in 1980/1990s

Functions of the control centres 1997

SCHEDULING GENERATION

- Planning ahead for the likely situation for 48 hours.
- Producing an indicative schedule.
- Checking which plant is available.
- Establishing the cost of generation at each plant.

DISPATCHING GENERATION

- Ensuring short term security of supply.
- Keeping the power system ready to meet demand at any time no matter what the schedule says.
- To achieve these goals, they must take into account the:
  - Status of the grid.
  - Equipment that is out of service.
  - Level of the HVDC (how much power is being transferred between islands and in which direction).
  - Amount of equipment needed to keep the lights on.
  - Weather, as even a two degree change in temperature can dramatically affect demand.

GRID CONTROL

- Real-time management of Transpower's transmission and communication systems.
- Close relationship with the Dispatcher because of the dynamics of the power system. To illustrate:
  - If a line is removed for maintenance, the Grid Controller needs to inform the Dispatcher to increase the voltage around the relevant stations. The Grid Controller is able to operate the circuit-breakers and switches by computer.

SUPPORTING THE MARKET

- Providing information to market participants to enable them to make their decisions. This information must be accurate and timely.

So system operation:

- Retained (and enhanced) its **management of reliability** – the job of managing all the complex physical aspects of a power system, especially the things that might disrupt supply interruption
- Increasingly enhanced the **economic process by which the use of resources was optimised***, to give assurance that the system was being run at least cost. This had both a scheduling (forward looking) and dispatch (assigning output) component.

In pursuing these twin objectives, by the late 1980s the newly corporatised "ECNZ" had:

- Undertaken a $40m SCADA, automation and remote control project, and
- created "an internal spot market as a basis for establishing stations as profit centres with market incentives"

* It is worth noting that the economic process only makes sense if there is discretion between competing resources; although this is always true if you consider shortage as a resource.

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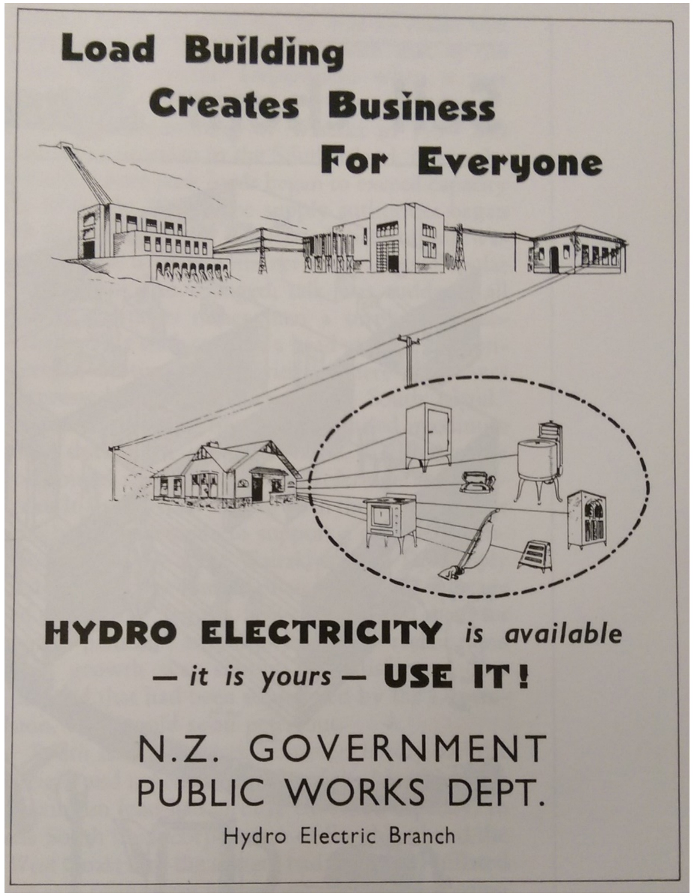
Pricing – the bulk supply tariff



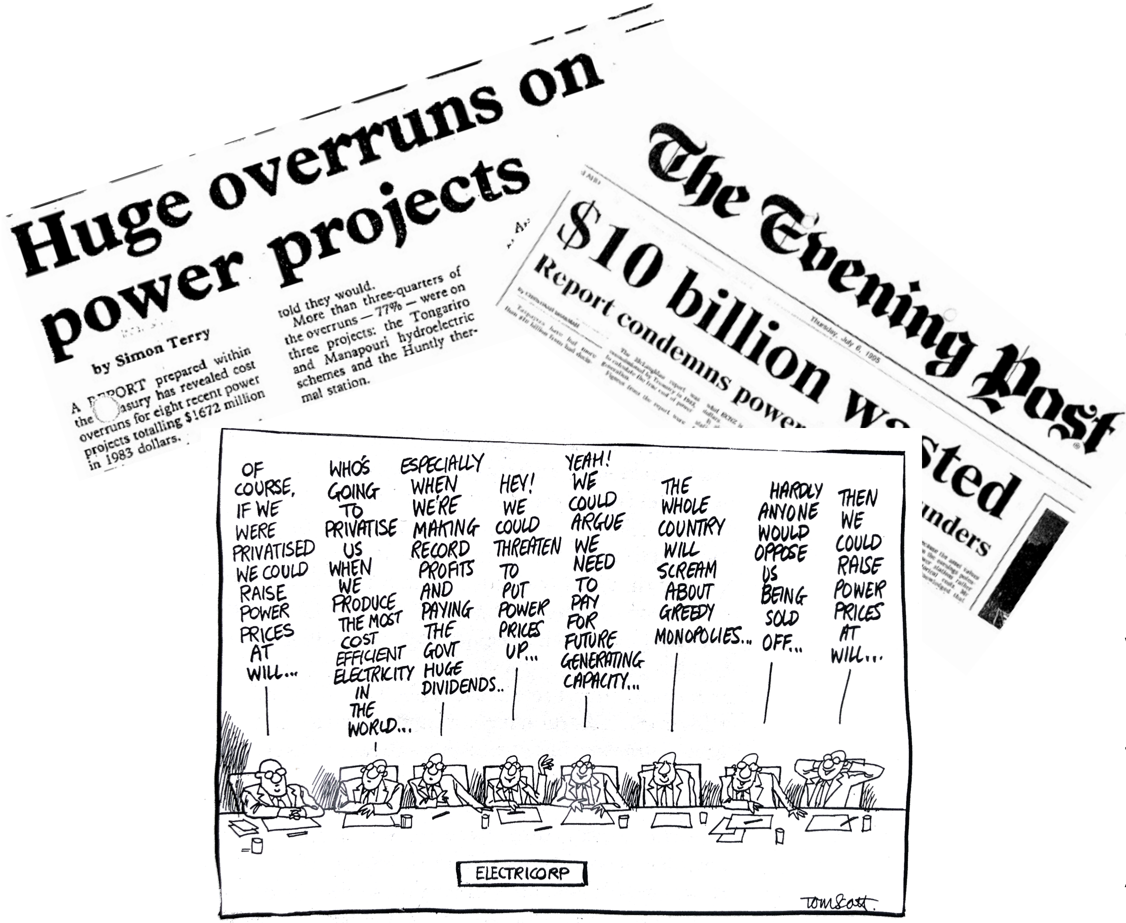
Until 1966, the “bulk supply” of power (by the state) to Electricity Supply Authorities was priced on the basis of maximum demand: the philosophy was that all costs were capacity related, and consumption was to be encouraged.

In 1967, this was changed to a demand charge on annual peak demand plus a volumetric energy charge. The rates set by the Public Works Department in 1967 were held constant (in nominal terms) by successive governments until 1976.

In two successive years, bulk supply prices were increased by 60% and 40% respectively. This was largely driven by a desire to promote the careful use of energy following the oil crisis, and the increase was internally justified on the basis that the new prices better reflected the long-run costs of electricity generation.

In 1988, ECNZ separated out the transmission component.

Motivations behind reform in the 1990s - pricing



Even then, as part of the disastrous commercial track record of government expenditure on power stations, the criticism of the Electricity Division of the Ministry of Energy in 1984 included non-commercial pricing.

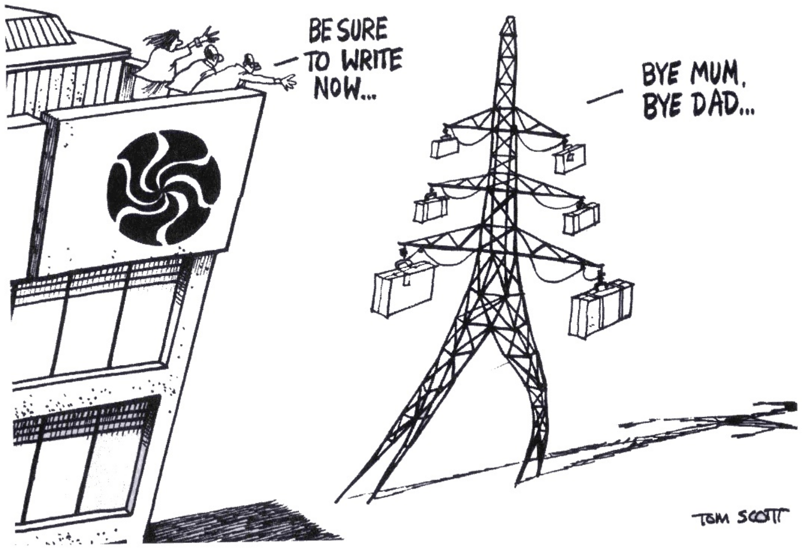
So the creation of ECNZ in 1987 had, at its core, an objective of acting commercially, bringing with it a focus on its bulk supply pricing (which now became "wholesale prices"). Counter to what many expected from a commercial monopoly, ECNZ allegedly* pursued entry-deterrence through its pricing, i.e., keeping prices low to deter the entry of competing generation, balanced against rate of return. It argued that, with surplus capacity, this was efficient.

By 1991, prices had declined 20% (real) and ECNZ began to consider the prospect for new capacity within 10 years and announced a 3% price rise.

All hell broke loose.

*Martin, John E (1998), People, Politics and Power Stations, p351

The motivation for a market



*An open access grid was considered by the government to be pivotal to enabling free competition: New supply participants needed to be able to connect to the grid on the same terms as the incumbent power stations. Retaining the transmission function as part of the incumbent monopoly generator would have created an untenable risk that new generators would have been denied connection on spurious grounds, or at least offered unfavourable terms, and thus would deterred their entry.

To cut a long (and politically complex) story short, it dawned on ECNZ that it had “crossed an invisible boundary defining what was possible.”

To de-politicise pricing, ECNZ began openly advocating for the establishment of a wholesale market: a level playing for capital of any type to compete on an open-access* arrangement.

Transpower had been separated from ECNZ in 1991, and took with it system operation; transmission charges weren’t separated from energy charges until 1993.

Remember the “economic optimisation” aspect of system operation? This had, at its heart, the notion of a “merit order” – power stations ranked in order of increasing variable cost. At its most basic, optimisation meant dispatching plant by working up this merit order until demand was satisfied. ECNZ took their internal market and turned it into a merit order, which it provided to Transpower.

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The motivation for a market

International progress on wholesale electricity markets

As New Zealand commenced its design exercise in the early 1990s, the idea of introducing wholesale competition to bulk electricity was not new – trailblazing jurisdictions were:

- Chile in the mid 1980s
- UK in 1990
- Norway in 1991 (integrating Finland and Sweden by 1997, and Denmark in 2002)
- Australia (Victoria) in 1994

The reforms had a common pattern of separating ownership of uncontestable parts of the supply chain (networks) from contestable (generation and – albeit rarely - retail), allowing generation to compete in wholesale "pools" with a variety of designs.

But this was still not a "market": the organisation which owned most of the generation (i.e., ECNZ) provided a set of costs and capabilities, and Transpower did what System Operation had been doing for decades: dispatching these stations at least cost while honouring any constraints on reliability (including transmission constraints, voltage, standby reserves etc).

The real work of designing an open market, where different suppliers would compete to deliver the lowest overall cost of meeting demand, began in earnest in 1992 by the "Wholesale Electricity Market Study" (WEMS) as a cooperative pan-industry group of experts.

The final design of the wholesale market was confirmed in June 1996, which gave Transpower 3 months to develop and implement the model software and systems required to run this bulk electricity market....

* A subsequent "Wholesale Electricity Market Development Group" (WEMDG) reaffirmed the direction, but noted that ECNZ's size was a sizeable obstacle to competition.

The model – Security Constrained Economic Dispatch

ECONOMIC DISPATCH

Maximise the net benefit of system resources

benefit of consumption – (cost of generation + cost of reserves)

The easiest way to think of this is as the model finding the least-cost combination of generation and reserves that meets security requirements (below). This was little different to what ECNZ and earlier system operators had been doing in practice for a number of decades, except that now the resources were competing with one another by offering their capability, and the cost of that capability.

Subject to…

SECURITY CONSTRAINED

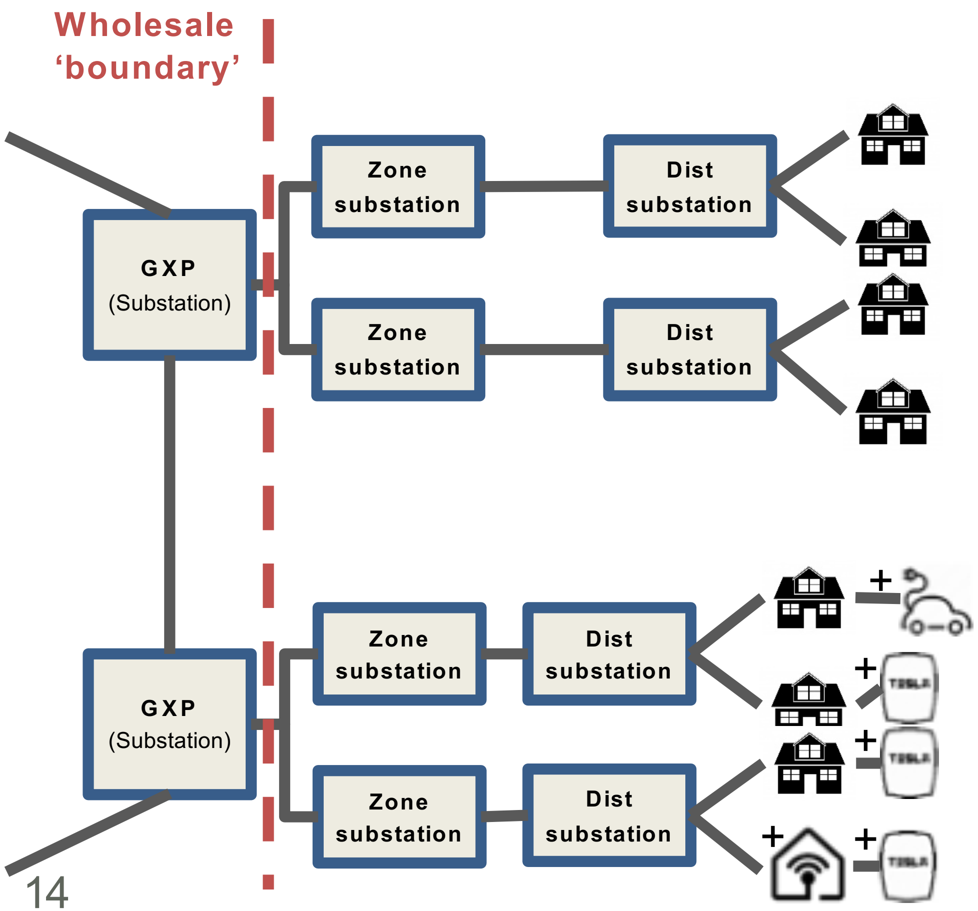
Avoid cascade failure:

1. Maintain sufficient standby reserves (generation + interruptible load) to cover the largest single failure
2. Apply constraints to power flows on transmission lines so that they do not exceed their capacity, including following a failure.

As we will see shortly, this is not the full extent of the methods, policies and practices the system operator employs to avoid cascade failure. But these are the requirements that are incorporated directly into the market model, and thus reflected in market prices – the model will find a dispatch solution which ensures these security requirements are met.

Note that the model produces dispatch of energy, and dispatch of reserves - it effectively solves for the optimal MW output. Constraints on voltage are not solved directly in the model, as it assumes that voltage is constant on the EHV grid. If an area of the grid has voltage issues, it is incorporated into the model via transmission constraints. This is likely to be quite different on the distribution network

Where was the grid (GXP) edge?



A common misconception is that the current wholesale market framework "stops" at the GXP, i.e., the security-constrained economic dispatch only considers resources and constraints that exist within the GXP boundary.

In reality, the rules anticipate that the boundary for dispatch relates to size, not connection location:

- Transpower models a small number of lines inside distribution networks where they allow power to flow in "parallel" to GXPs
- Generators over 10MW connected at distribution level face the same offering and dispatch obligations as those connected directly to a GXP
- Generators over 1MW connected at distribution level must notify….

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Scheduling, Pricing and Dispatch (SPD)

13.57 The dispatch objective

The **system operator's dispatch objective** is to maximise for each **half hour** the gross economic benefits to all **purchasers** of **electricity** at the **grid exit points**, less the cost of supplying the **electricity** at the **grid injection points** and the costs of **ancillary services** purchased by the **system operator** under subpart 3 of Part 8, in accordance with the methodology set out in Schedule 13.3, subject to—

(a) the capability of generation, **dispatch-capable load stations** for which a **nominated dispatch bid** was submitted, and **ancillary services** and the configuration and capacity of the **grid** and information made available by **asset owners**; and

(b) achieving the **principal performance obligations** and any arrangements of the type described in clause 8.6; and

(c) meeting the requirements of clause 8.5 in relation to restoration of the power system—

provided that in the case of any conflict between paragraphs (b) and (c), paragraph (c) takes priority.

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8 The objective function

(1) The objective function of the modelling system is described mathematically as:

$$\text{Maximise}\left\{\begin{array}{c}\overbrace{\sum_{i,j} D_{i,j} \times BP_{i,j}}^{\text{Gross Consumer Benefit}} \\ \text{minus} \\ \overbrace{\sum_{i,j} G_{i,j} \times OP_{i,j}}^{\text{Cost of Generation}} \\ \text{minus} \\ \overbrace{\sum_{i,j} R_{i,j}^{PLSR,f} \times OP_{i,j}^{PLSR,f} + \sum_{i,j} R_{i,j}^{TWD,f} \times OP_{i,j}^{TWD,f} + \sum_{i,j} R_{i,j}^{IL,f} \times OP_{i,j}^{IL,f}}^{\text{Cost of Fast Instantaneous Reserves}} \\ \text{minus} \\ \overbrace{\sum_{i,j} R_{i,j}^{PLSR,s} \times OP_{i,j}^{PLSR,s} + \sum_{i,j} R_{i,j}^{TWD,s} \times OP_{i,j}^{TWD,s} + \sum_{i,j} R_{i,j}^{IL,s} \times OP_{i,j}^{IL,s}}^{\text{Cost of Sustained Instantaneous Reserves}}\end{array}\right\}$$

Part 13 of the Code

The combination of security constraints and economic (least-cost) dispatch is a classic optimisation problem. Through some approximations*, the mathematical formulation of this problem can be solved for the entire grid very fast (minutes).

And formulate it mathematically we did. And NZ was the first in the world to:

- Incorporate transmission losses
- Solve the standby reserves problem at the same time as we solved the energy problem – i.e., the dispatch solution was the optimal solution to both problems. Other jurisdictions solved these problems separately
- We boldly went where no man had gone before on pricing; **the idea of basing all physical transactions on transparent (published) prices, was central to the "level playing field" notion behind the wholesale market**.

What do “efficient prices” look like?

1. The most efficient price signal to send consumers and producers in the short-term is the short-run marginal cost of meeting demand.

Ideally, this needs to reflect two locational dimensions:

1. The marginal cost of transmission losses
2. The marginal cost of local supply if cheaper power cannot be imported due to transmission constraints

2. The long-run costs of building new supply resources are either met through allowing SRMC pricing to rise to the point where it delivers the required return, or by agreeing long-term contracts for the supply of power (which settle against the SRMC signals)

This has significant implications for how we implement “scarcity” pricing (pricing during shortage of energy or standby reserves). Some jurisdictions chose instead to implement “capacity markets”* to help send signals of the need for new capacity.

*A “firm energy” market was part of the original market design, but it was rejected due to implementation difficulties – political and technical

Scheduling, **Pricing** and Dispatch (SPD)

Every half hour, generators sell, and bulk purchasers (retailers, large industrials) buy, at the specific price calculated for the GXP they connect to.

Average Nodal Price* by Region

Average Price All New Zealand: $61.03

*All prices in $/MWh. Average prices are demand weighted

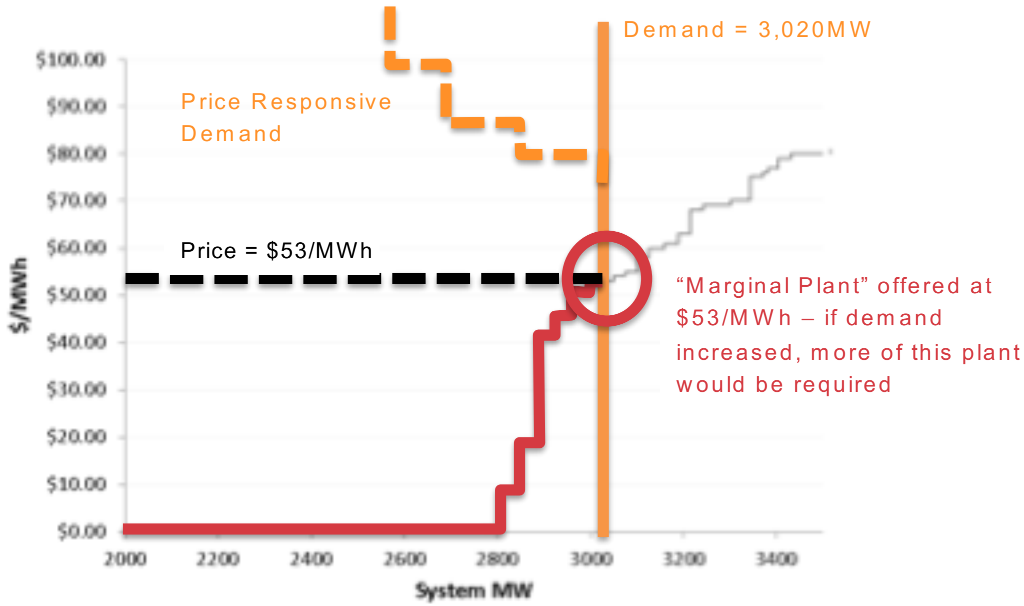
It goes without saying that "sending price signals" requires the market participants to actually transact at these prices – i.e., purchases of electricity pay these prices, and suppliers of electricity get paid these prices.

It so happened that SPD is able to directly produce market-clearing prices* every time it solves, and for every location on the grid. This is known as "locational marginal pricing" or "nodal pricing".

These prices are used for settlement of payments in the market.

*Mathematically, this is more remarkable than you think – but is a major advantage of being able to simplify the market model to effectively ignore voltage. This is unlikely to be possible on the distribution grid.

The market in pictures



Generators compete by offering their generation capability at a price, and the market model selects the lowest cost combination.

This graph is a conceptual illustration of what the market model is effectively doing. The market price is set by the "marginal plant": if a consumer wanted one more MWh of demand, this is the lowest-cost plant that we could use to increase output.

In a zonal market, the market price would be equal to the short-run marginal cost of this plant ($53/MWh in this case)

In a locationally priced market, the market price at each location in the network is the offer price of this plant PLUS the marginal cost of losses of transporting the extra MWh to each location in the country.

And, potentially, there could also be congestion effects if transmission flows are constrained, and reserve effects if the marginal plant is also setting the reserve "risk".

A world-leading design

1. New Zealand was the first country in the world to integrate these two components into the one market optimisation along with the merit order.

Market Design

A half hourly "spot market" where generators indicate their willingness to generate through "offers", and consumers (retailers) indicate their willingness to buy through "bids" => provides the merit order, and energy component of SRMC

An underlying model of the transmission system whereby transmission losses and constraints could be incorporated

A "reserve market" with two standby reserve products to deal with unexpected failure of large generation (or the HVDC)

A contract market (ASX and OTC) for securing long-term contracts for power supply/consumption.

2. In doing so, this optimisation (known as the Scheduling, Pricing and Dispatch model, or SPD) was more than just an optimal economic dispatch model, it was a "security constrained" economic dispatch model, as it integrated some of the system operator's security requirements into the economic evaluation.

3. It also allowed the direct production of locational marginal prices at ~250 points on the transmission system – an economist's dream!

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Security constrained economic dispatch for DER?

Were there concerns that competition couldn't coexist with security needs?

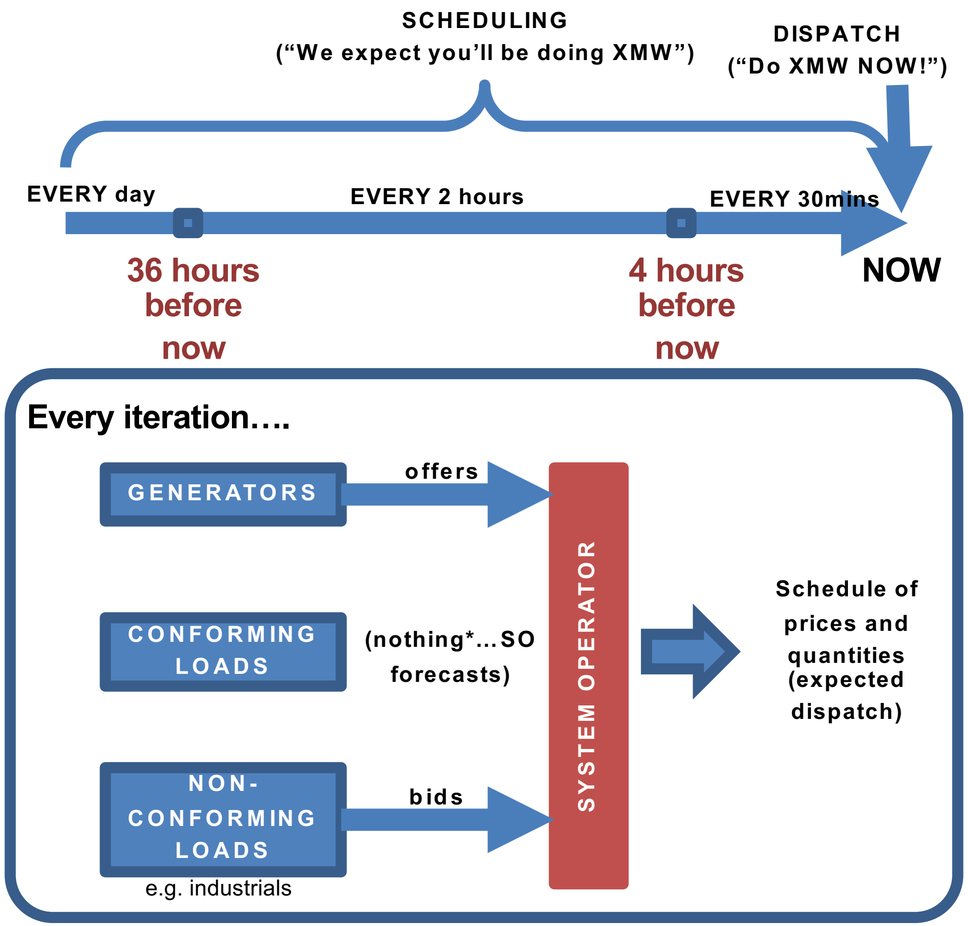
An international conference on large high voltage systems (CIGRE) held in Paris in September 1992 expressed a consensus view that some forms of competition introduced around the world had impacted adversely on overall power system reliability. Also, that it is clear that co-ordination of generation, transmission and distribution is essential for both planning and operation of a national grid **and that in most countries the coordination of system reliability and economy is best achieved by one central computer system.**

Could a broken-up and competing electricity generation system, selling into a wholesale electricity market, respond as rapidly to a major electricity outage at a time of peak demand as a centrally co-ordinated electricity generation system?

J P BLAKELEY

19 JANUARY 1993

Forecasting vs Dispatching



Above a minimum size, all generation is required to "offer" into the market. This offer describes both its capability and its (commercial) desire to provide (and change) output.

Most demand is forecast by the system operator, but "non-conforming" loads, or any dispatchable demand response, must provide bids to reflect their desire to consume.

The scheduling and dispatch process built in a highly iterative approach to every "trading period" (half hour), where the SO runs the market model on updated offers, bids and forecasts, and thus gets gradually more confident about what will happen when it arrives. This information is provided to the market.

In real time, anything that is offered must obey the dispatch instructions of the system operator – without this requirement, the system operator's security assessments are in vain.

* Conforming loads may offer "difference bids" to indicate if they would change consumption at a particular price. These bids would be included in the "Price Responsive Schedule",

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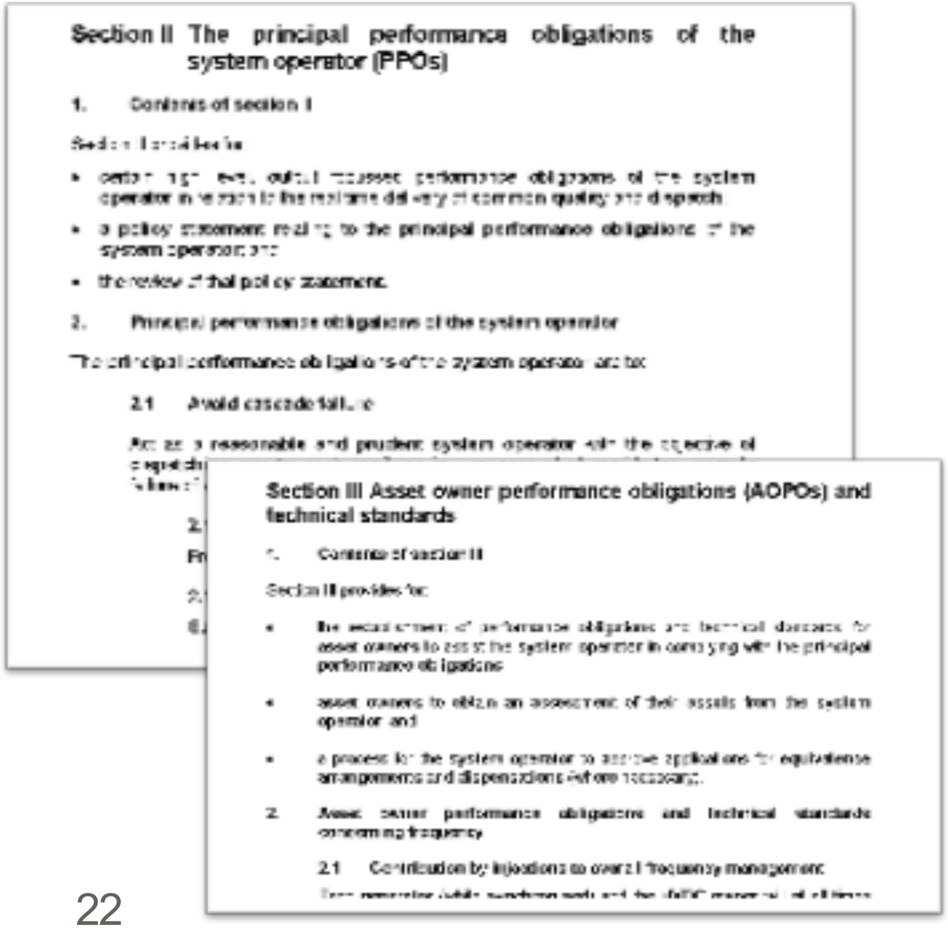
System Operation and Common Quality



Despite the presence of a market, where a diverse set of market participants are free to participate (economically), modern wholesale markets maintained a “common quality” framework which was designed to:

- **Coordinate** the actions of this diverse set of participants
- **Avoid cascade failure**, which, as an objective, was translated into a set of “principal performance obligations” (PPOs) on the system operator

The system operator was given a broad remit to take *prescribed* actions to achieve its PPOs, but was also granted the discretion to intervene if it felt market outcomes were threatening security and reliability.

But, even broader than the SO’s PPOs, performance obligations were placed on asset owners (AOPOs) that helped the SO meet its PPOs, and/or helped coordinate the actions of market participants.

Multilateral Agreement on Common Quality Standards

2.2.3 Limit rate of occurrences of momentary fluctuations

Subject to rule 3, act as a reasonable and prudent system operator with the objective of ensuring that the aggregated rate of occurrence of momentary fluctuations experienced in the North and South Islands of New Zealand does not exceed the statistical equivalent of the following levels:

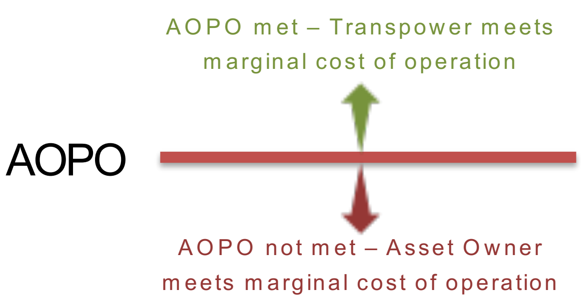
Frequency Band (Hertz) (where "x" is the frequency during a momentary fluctuation)	Maximum number of occurrences by period (commencing on and from the operational date)
52 > x ≥ 51.25	7 in any 12 month period
51.25 > x ≥ 50.5	50 in any 12 month period
49.5 ≥ x > 48.75	60 in any 12 month period
48.75 ≥ x > 48	6 in any 12 month period
48 ≥ x > 47	1 in any 60 month period

The first effort towards agreeing these common quality standards was attempted in the pre-regulated voluntary governance environment, and was known as the "Multilateral Agreement on Common Quality Standards", or MACQS.

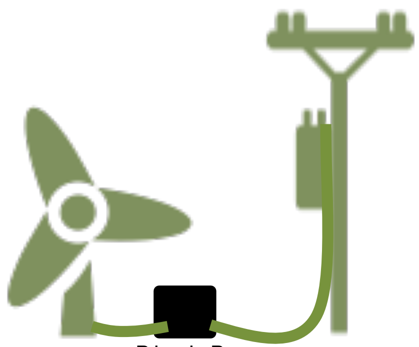
There was quick acceptance that denoting absolute limits was practically impossible or economically undesirable, hence while standards were stated as outcomes or "objectives", i.e. AOPOs, PPOs., many objectives, e.g. frequency, were probabilistic.

Equivalence and Dispensation

Dispensation could turn a hard constraint into a soft constraint – compliance wasn't required if it had limited effect



Equivalence provided for least cost solutions that still delivered



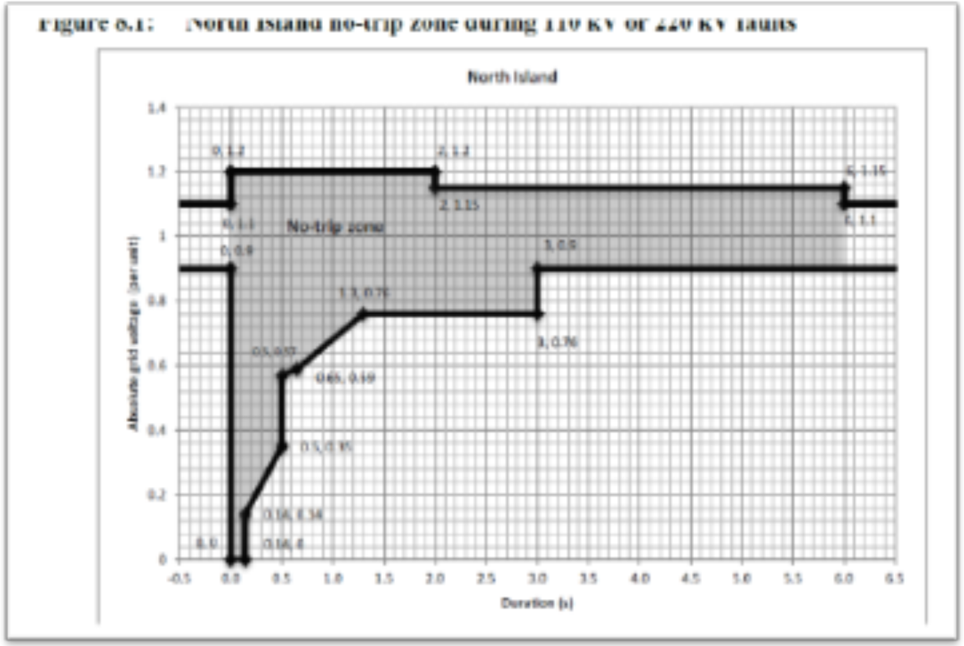
Dispensation – Asset owners could apply to not have to meet objectives provided they meet the costs of non-compliance (if any)

Equivalence – asset owners could meet objectives through providing an approved equivalent arrangement

BUT

- Existing asset owners lobbied hard for permanent grandfathering arrangements
- There was no observable price for common quality products to give asset owners a basis to assess potential costs under dispensation, which also affected equivalence
- The evolution of MACQS was interrupted by the establishment of the Electricity Commission with the MACQS rules becoming Part C

MACQS rules have still worked



MACQS became Part C of the Electricity Governance Rules and Parts 7 & 8 of the Code

Changes to the obligations have been based on economic criteria subject to physical reality

- Frequency obligations for generators
- SI AUFLS
- NI Over frequency arming
- National markets for frequency and potentially reserve
- Fault voltage ride-through

More than just a model – real time operation

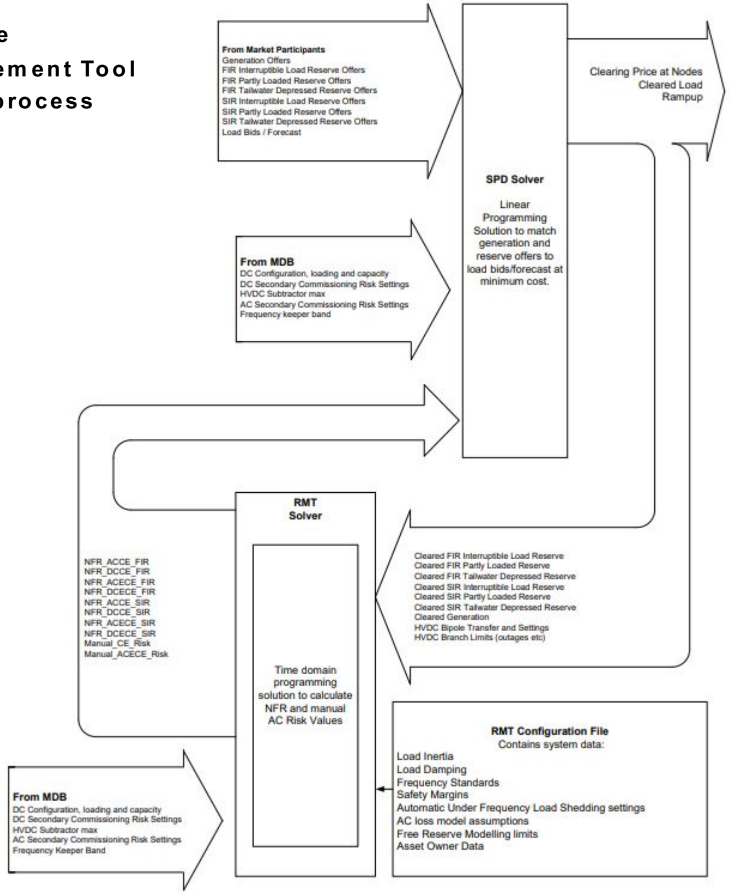
Historically these tasks have been completed offline using complex powerflow and time domain simulations; potentially these tools have not captured the true dynamic nature of system stability (as it is state-dependent). As computing power has improved, more of these "offline" assessment tasks are being done online, as the computations can take place with such speed to allow operator reaction or even, potentially, automated response (Nair *et al*, 2012).

While the System Operator does the half-hourly crunching of the (security constrained) optimal dispatch, and sends these dispatch instructions to the power stations (or demand response providers), it must maintain a series of security tools which monitor a number of aspects of power system security in real time:

- The underlying power system model in SPD assumes voltage is constant on the grid: however, there are parts of the grid (e.g., Auckland) where voltage must be monitored, and, in some places, dispatch must be constrained to maintain voltage
- Within any half hour the System Operator needs to discretion to vary dispatch as conditions vary second by second.
- The System Operator relies on Asset Owner Performance Obligations (AOPOs) that effectively require power stations to behave according to minimum standards during a disturbance

Real-time operation is actually about planning

Reserve Management Tool (RMT) process



Real-time operation for normal operation is not real-time, it's about planning

Identifying previous issues and adapting rules, processes, and temporary constraints/inputs for various scenarios

Real-time operation is about managing contingencies, mostly with tools, e.g. RMT, VSAT, FSAT, ancillary services

Where something unexpected occurs the SO has discretion under the guidelines in a Security Policy

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Evolution

To a large extent, the process of market design is never done. This is expressed eruditely by MIT Professor Paul Joskow:

"Replacing these [traditional] governance arrangements with well functioning decentralized market mechanisms is a very significant technical challenge, about which even the best experts have disagreements. Accordingly, it should not be surprising that electricity restructuring and competition programs have inevitably been a process that involves a lot of learning by doing and ongoing changes to market rules, regulatory arrangements, and governance institutions."

"The difficult transition to competitive electricity markets in the U.S.", Paul Joskow, 2003.

NZ's market design, and its fusion of economic criteria (including pricing) with the hard physical constraints of security and reliability, has existed largely intact for over 20 years.

But significant enhancements have taken place over this time:

- Incentives to manage hydro security
- Development of hedge market
- Market systems upgrade
- Increase in online security assessments
- Development of voltage stability constraints
- Scarcity pricing

International comparisons

Independent system operators (ISOs) means different things to different people.

Joskow (2005, 2007) reports that the creation of ISOs (and associated Regional Transmission Organisations, or RTOs) in the US was motivated by the "balkanisation" of regional transmission grids that crossed state boundaries. FERC's Order 888 in 1996 suggested that, ideally system operation and transmission access needed (functional) unbundling from generation and retail (to allow independent generator access), but stopped short of requiring structural separation. In fact (and ignored by Joskow), Order 888 established a principle that ISO's, if created, should actually be independent of transmission owners.

While some jurisdictions (e.g., California) then established ISOs, this was not required by FERC until Order 2000 (1999) as the issues with managing open access and wholesale markets across multiple transmission networks became acute. The requirement was separation of transmission ownership and investment from just about everything else – tariff setting, operation, investment assessment and system operation – to reduce the difficulties associated with managing power flows across multiple transmission owners.

Effectively, NZ decided to manage the fusion of open access, economic and security objectives by:

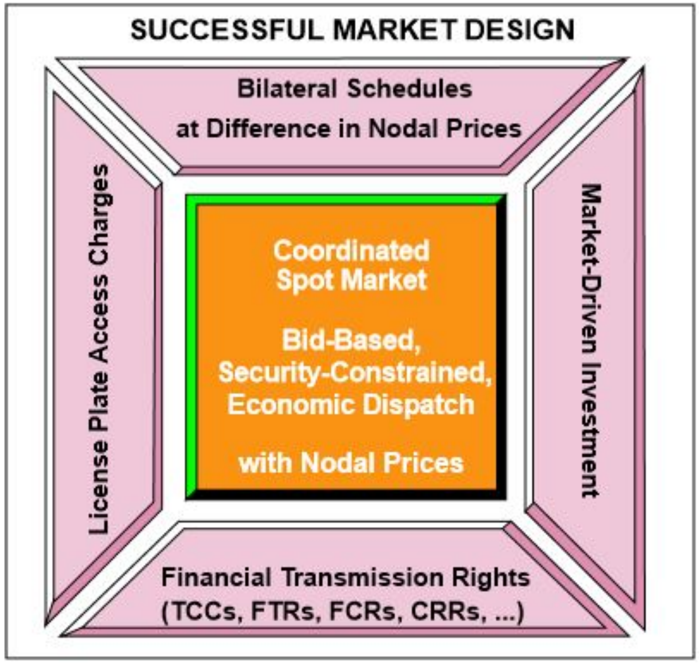
- Allocating the task of security constrained economic dispatch, and security monitoring to a single entity: Transpower.
- Requiring that the System Operator ringfenced its operation from the grid owner, so as not to compromise its discretionary decisions (bias in favour of grid owner, who also offers asset capability into the market)

Some jurisdictions structure this differently:

- E.g., Philippines separates a "Market Operator" from "System Operator", with the latter having no influence over economic decision making
- E.g., US which requires that the system operator be formally (structurally) independent; some (TSOs) are also responsible for system planning.

International comparisons

William Hogan (Harvard) on market design – connecting the short and the long term market design problems:



But broadly, many jurisdictions have adopted wholesale reforms, and there is a generally accepted design framework.

Experts quibble over the relative importance, but:

- A market that asks for bids and offers from market participants, and clears on SRMC, is almost universal.
- While LMP is seen as the ideal, some jurisdictions have chosen (for a variety of reasons) to stick with zonal pricing
- The primacy of keeping the lights on - ancillary services are critical to achieving stable, reliable systems
- Open access networks, where any party can connect on a standard set of connection criteria.
- System operation being independent from market participants, and necessary to achieve standardisation and coordination

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Learnings?

The process of matching demand with supply is a real-time technical <u>and</u> economic decision; the economic aspect has been there since the point at which the industry had discretion over different resources.

Over the last century, system operation became more and more sophisticated at this economic/technical decision making. Industry came together eventually and developed a way in which economic/technical decision making could be integrated into a “market” where owners of “resources” (including demand) were able to make their own economic tradeoffs.

This did not result in a loss of control over security and reliability as a result of:

- The market dispatch and pricing engine (SPD) ensuring economic dispatch was constrained by a fundamental security requirement
- A system operator retaining real time control
- A set of asset owner obligations and planning standards (which are based on an underlying economic framework) which supported this.

This - achieved for the grid in 1996 - is surely achievable for the distribution network?