Electricity contracts

Composition and risk allocation in the New Zealand electricity market

NZIER working paper 2006/01

in association with Strata Energy Consulting Ltd

Public discussion document

January 2006

Preface

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Executive Summary

Upward pressure on fuel prices for use in electricity generation has contributed to increases in the prices faced by all consumers of electricity in New Zealand. Some commercial and industrial users have been hit particularly hard, with some having to temporarily cut back production as prices become prohibitive.

The price changes have varying effects on these commercial and industrial users depending on the structure of their contracts, and their levels of exposure to the different risks inherent in them. While some users will be aware of the components that make up their total electricity price (or price formula) others may not be fully aware of both the explicit and implicit elements. The importance of understanding the potential impacts of these components is heightened in periods of change.

This paper identifies the typical components of electricity contracts for non-residential users, identifies the potential risks around each component and suggests issues for users to consider in terms of their existing and future contracts.

The key findings and recommendations of the paper are:

- Both the costs involved in generating electricity, and the variability of spot market prices will have significant impacts on the prices paid by users. If the generator is offering a fixed price contract to a user, they will use the information about the cost of production in helping set the offer price. While the generator will clearly look to achieve the highest price possible, it will at a minimum need to at least cover its variable costs in order to make it worthwhile generating. This is true both for existing costs and expected future generation costs, so the offer will include their assessment of how inputs into production (typically fuel) are expected to change over the contract period. The generator will also consider its opportunity cost in offering a contract to the user - the price it would have received selling the electricity on the spot market.
- For the user, the type of contract being offered is important in terms of exposure to different prices. The user needs to consider the relative risks associated with fixed vs. spot prices, given their influence via the contract being offered. They must consider the potential influences on the spot price, and how this will affect both contract elements which may relate to the spot price (e.g. via a price formula) and the risks associated with buying directly from the spot market.
- In terms of spot price variability, for users there are limited options for reducing any exposure to spot price volatility other than managing load (e.g. reducing or shifting). It will be important for them to assess how their price or pricing formula treats spot price variations (i.e. is it a fixed price, average annual price etc). Some firms will be better able to handle variations in spot price, although all should consider what is their 'switch price' at which electricity price spikes will make the costs of production uneconomic.

- The effect of dry years (in hydrological terms) can potentially have significant impacts on the spot price for electricity, and depending on the formula for price, on the cost to the user of purchasing electricity. Prices are asymmetric i.e. prices increase more in dry years than they decrease in wet years and so users need to consider their risk appetite, or whether they would prefer to pay a premium to have another party cover the risk. Dry year price spikes can be significant, although the Electricity Commission has introduced some measures to reduce their impacts (e.g. reserve generation at Whirinaki).
- The potential for a carbon related charge should be considered in contracts. Contracts should contain a provision for good faith negotiations to occur should a charge be introduced, on terms which do not unfairly impact on either party. The government has announced that it will not be proceeding with the carbon tax as previously announced but has not ruled out other types of charges. Parties will also need to ensure a process for dispute resolution is allowed for, should negotiations for the inclusion of the charge not be completed successfully.
- CPI and PPI price escalation factors are quite common in contracts, but their volatility is generally more stable than other components such as any dry year risk or general spot price volatility.
- Users should gain an understanding of any nodal price risk they face. Transmission constraints can potentially cause large spikes in price at particular nodes. 'Spring washer effects' can amplify these price increases significantly at nodes around a transmission loop when a constraint binds on one part of the loop. The potential burden of risk depends on the attribution via the price or price formula, but users should be aware of the constraints that exist for their relevant nodes and any plans to upgrade the transmission system associated with a node (or nodes). They should also consider for example, analysing historical information on the effects of constraints on nodal prices as a potential indicator of future price spikes should any constraints continue to bind[1].
- Users should ensure that their contracts are clear in their definition of what is a force majeure event (i.e. unforeseeable, unavoidable, beyond the control of the defaulting party) as opposed to covering plant outages via a suspension clause. They should also ensure that prices reflect the risks these clauses can impose upon them.
- Other components such as market levies and costs and credit risk may be less explicit in contracts but will definitely be allowed for in the final price. They will also allow for the suppliers assessment of the risk of regulation and government risk. There are avenues for users to monitor these risks themselves.
- Users not directly connected to the transmission network should be aware of any margins applied to transmission and distribution charges relating to their energy supply (whether explicit or bundled) and whether they are receiving their appropriate share of loss and constraint rentals paid to the distribution company which carries their energy. These rentals should be identifiable as an

[1] However, as the transmission system and the energy flows across it are dynamic, historical levels cannot be relied on in isolation as indicators of future prices.

explicit payment to be received by the customer or an appropriate reduction in charges.

In summary, electricity prices and contracts are complex and contain important risk components in both the price and contract terms. Users will be charged premiums where the electricity supplier perceives there is greater risk to them. Users may also gain value if they can identify and reduce the risks faced by suppliers.

Understanding how these components apply and relate to individual supply contracts is essential to being an ‘informed’ electricity consumer.

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1. Introduction

The New Zealand energy sector has come under the spotlight in recent times, with numerous changes and events along the energy supply chain causing wide-ranging impacts on participants within the chain. The fuel supply situation, the establishment of the Electricity Commission and uncertainty around the potential for a carbon charge for example have, and will continue to have, major impacts on the way in which energy is supplied, and the prices users pay for purchasing energy. The changes have also impacted on the contracts held by energy users, and the terms and conditions which are made available to them. The prices paid through these contracts represent the amalgamation of a number of components and it is these components which have been affected in various ways by changes in the market.

This paper focuses on contracts for the purchase of electricity by non-residential users and the components that make up their 'typical' electricity contracts. It looks at the allocation of risk within these typical contract types and how changes in the industry have altered the influence of some components that make up the total price of purchasing electricity. It also provides some points for users to consider in terms of their own existing contracts, and when considering the terms and conditions for new contracts.

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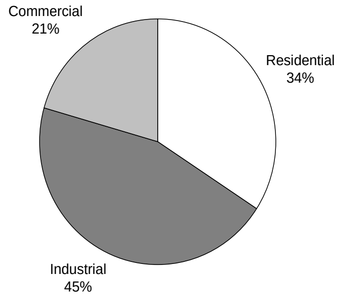
2. Background

The New Zealand electricity market is dominated, in terms of demand, by large industrial users. These users account for around 45% of total electricity demand, with commercial users accounting for another 21%. Within the industrial sector, electricity demand is dominated by a relatively small number of energy intensive industries.

Figure 1 Consumption shares of total electricity demand

Percent. March year 2004.



Source: MED – Energy Data File January 2005

Most of these large industrial and commercial users purchase electricity through a retailer, similar to a residential user. Indeed, most electricity consumed is bought via direct bilateral contracts between a consumer and a retailer in one form or another. Only a relatively small number buy electricity directly through the wholesale spot market, and several of these still buy the majority of their electricity from retailers.[1] Comalco for example, New Zealand's biggest single user of electricity, have a fixed contract with Meridian Energy for the bulk of their electricity purchases, with the remainder purchased directly through the spot market. Alternatively, some major users generate their own electricity to satisfy a proportion of their demand through on-site co-generation.[2]

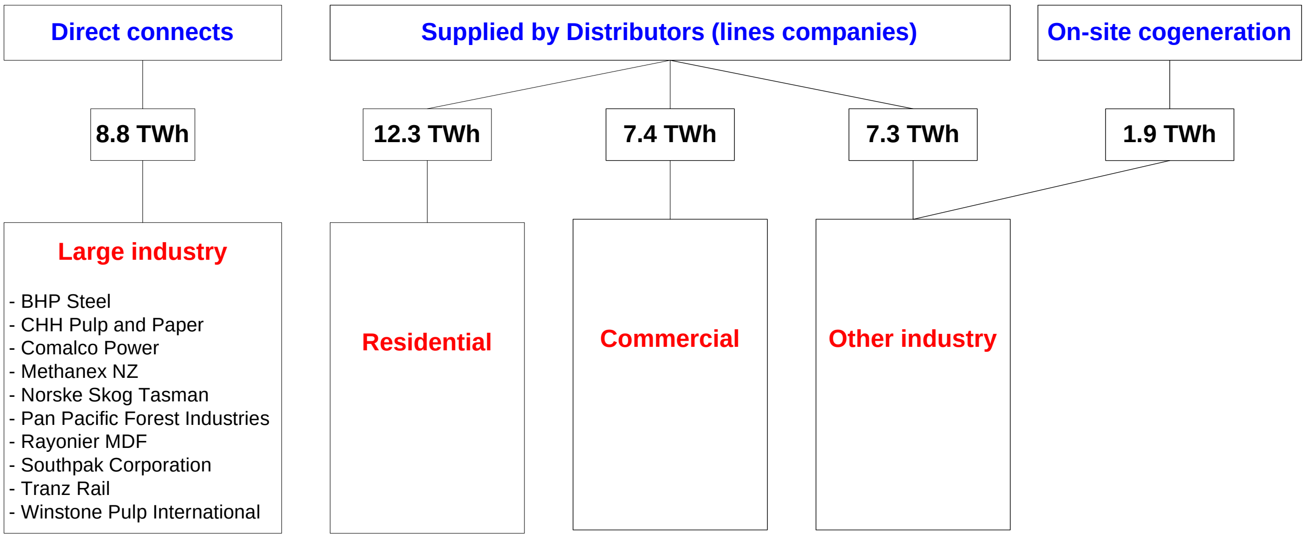
In addition, there is also variation in the way these larger users have their electricity supplied. Figure 2 below shows that a number of large industrial users are directly connected to the transmission network, rather than receiving electricity via the distribution network as residential and commercial customers do. Such users are often referred to as 'direct connects' i.e. directly connected to the transmission network.

[1] Given that the retailers are also generators, most electricity is thus bought under bilateral contracts between consumers and generators.

[2] NZIER report to the Electricity Commission, *Market Design Report – Initial Stock-take Paper*, August 2005, p.43.

Figure 2 Electricity flow summary by supply source

TWh. March year 2004.



Note: Some large industrial users who are 'direct connects' may also have some on-site generation.

Source: Adapted from MED – Energy Data File January 2005.

These variations in the way electricity is purchased flow through to variations in the contracts between the consumer and the supplier (who could be a retailer, generator or the spot market). Various contracting options include[3]:

- Buying on the basis of the spot price (variable price/variable volume), providing they have an appropriate meter;
- Buying on the basis of a fixed price/fixed volume contract through a retailer for a negotiated term. In some cases, fixed prices and volumes can vary on a monthly, seasonal or even daily/weekly basis. Any volume above the maximum is charged for at some average of spot prices;
- Buying on the basis of a fixed price/variable volume contract for a negotiated term. Again, fixed prices can vary monthly, seasonally or even daily/weekly; and
- Buying financial swap contracts for either fixed volumes or sculptured volumes. These are settled in cash monthly.

It is also possible that purchases may be made on a combination of the above options to make up a portfolio approach.

It is the fixed prices referred to in the various contracting options noted above which potentially contain a number of components which are the subject of this report. These components could be aggregated together in the form of a single price, or alternatively included as separate components. They could also be in the form of a price formula (as opposed to a single price), often containing escalation factors or derivatives of the components we discuss in the following section.

[3] NZIER report to the Electricity Commission, *Market Design Report – Initial Stock-take Paper*, August 2005, p.46

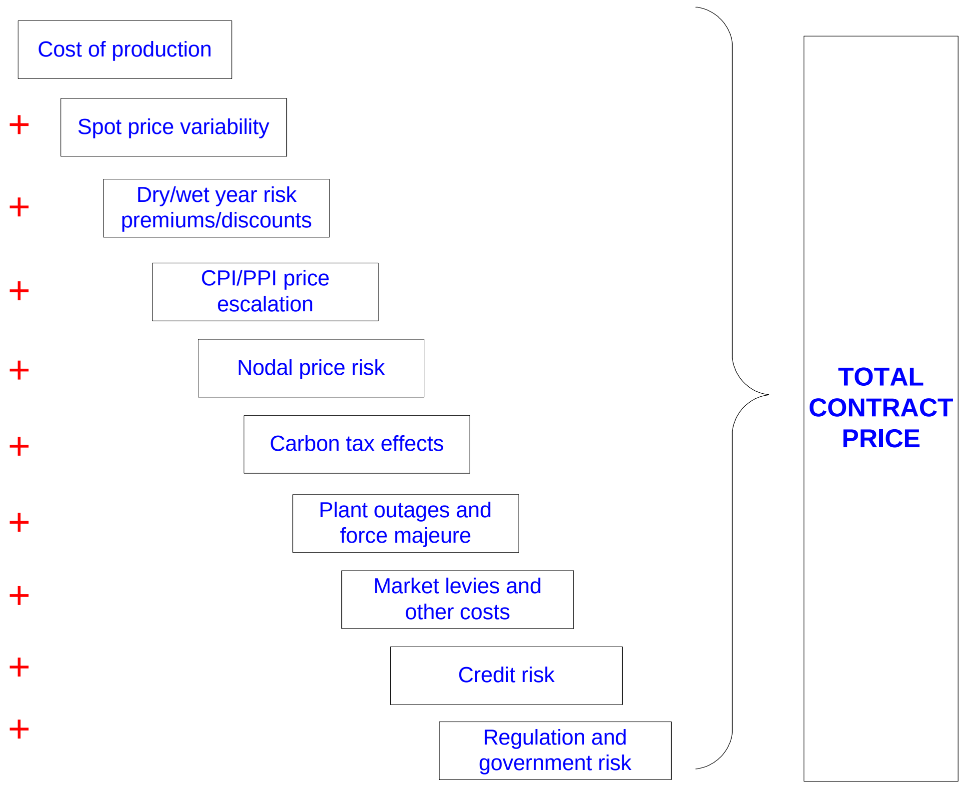
In the following sections we discuss just what the components of these fixed prices (or price formulas) could include, the risk relating to their volatility and issues for users to consider in relation to their inclusion in their own contracts.

3. Typical contract components

As we noted above, the price being charged to a user for electricity could potentially range from a single 'all inclusive price', to a series of individual component charges. The level of aggregation and just how explicit/implicit the components are in a contract is likely to vary significantly between users. Given that each of the components inherently contains a certain level of risk, we can be certain that the party offering the contract will have taken account of each component, regardless of how explicit it is in the fixed price or formula offered.

The typical components are shown in the figure below, and are described in the following sections. Note that below, and in the bulk of the discussion, we exclude the cost of transmission and distribution services and focus on the energy price components.

Figure 3 Typical contract components



Source: NZIER, Strata Energy Consulting Ltd.

Note: Transmission and distribution will be in addition to the components outlined above.

It should be noted that the value or premiums associated with each of contract components is likely to be dependent on the term the contract will apply for.

3.1 Cost of production and spot price variability

Both the costs involved in generating electricity, and the variability of spot prices will have significant impacts on the final prices paid by large users.

For generators, the cost of production will vary depending primarily on the type and scale of generation. The costs will include both fixed and variable components.

The fixed components typically relate to the capital cost associated with the plant and infrastructure, as well as operation and maintenance (O&M) costs (such as labour, administration) for this capital equipment. These fixed costs can vary considerably on a comparable per kW basis depending on the type and scale of generation. The cost of production will also include an allowance for a return on the generation investment (the fixed component). This will be introduced via a weighted average cost of capital (WACC) which is required to be returned from the investment. The WACC will vary depending on the scale and type of generation, and the companies profile itself.

The variable costs primary relate to the cost of fuel i.e. gas, coal, water etc. but also include variable O&M costs. These are referred to as being the short-run marginal cost of operating (or SRMC). The total variable costs take into account characteristics of the generation such as availability and efficiency. For generators using gas, coal and oil the variable component is likely to contribute the majority to the total cost of production and has been increasing in recent times. Indeed we have witnessed a step change in electricity prices faced by users, resulting partially from increased gas prices.

If the fuel being used by the generator creates carbon emissions, then there is a possibility that some carbon charge element could also be included in the future. The government had initially been set to introduce a tax on a per tonne CO_2 basis from April 2007, however it has recently announced that it will not go ahead as planned.[4] This is discussed further in section 3.5.

If the generator is offering a fixed price contract to a user, they will use the information about the cost of production in helping set the offer price. While the generator will clearly look to achieve the highest price possible, it will at a minimum need to at least cover its variable costs in order to make it worthwhile generating. That is, if the price the generator receives for an additional unit of electricity cannot cover the variable costs associated with producing that unit, it does not make sense to generate it. This is true both for existing costs and expected future generation costs, so the offer will include their assessment of how inputs into their production (typically fuel) are expected to change over the contract period.

It will also consider its opportunity cost in offering a contract to the user, which would be the price it would have received selling the electricity on the spot market. While by offering the contract they 'lock in' some demand, they forego the

[4] http://www.stuff.co.nz/stuff/0,2106,3519195a10,00.html – 21st December 2005.

opportunity to sell that same electricity via the market. The contract price offered to the user, will thus include an allowance for its assessment of the risk they take on by setting a fixed price for the contract period. For example, they will potentially forego high prices associated with any dry years which may occur, but equally will not face the possibility of low prices should a wet year reduce spot prices.

For the user, the type of contract being offered is important in terms of exposure to different prices. We noted earlier that the spectrum potentially includes all inclusive fixed price contracts and others which may retain some link to spot prices, with the alternative being purchasing directly through the spot market. The user thus needs to consider the relative risks and merits associated with fixed vs. spot prices, given their influence via the contract being offered. For example, the user must consider what potential influence changing fuel prices could have on the marginal generator (and thus the spot price), as well as the likelihood of events such as dry years and transmission constraints affecting prices. These factors will impact on both contract elements which relates to spot prices (if any), and the opportunity cost associated with buying directly from the spot market.

If the exposure is faced by the user i.e. they buy through the spot market, there are few options available to mitigate the effect of volatile spot prices. If their use is maintained at a constant level, then costs will rise as the spot price increases and vice versa as the price falls. Often the only option for users (particularly large industrial users) is to reduce consumption during periods of high spot prices. Firms typically have price limits for electricity, which when breached, mean that it is not economic to continue to produce output. For example, recent spot price increases led New Zealand Aluminium Smelters (NZAS) to reduce production at its Tiwai Point smelter by 5%.[5] There will be significant variability in different firms' ability to handle spot price volatility. Some firms will be able to accommodate price fluctuations, but others are likely to be willing to accommodate a premium for the generator to manage or take on the price risk. Key variables will include the type of product being produced by the electricity user, their scale and the margins involved in their production. All users should consider their 'switch point' i.e. at what price will purchasing electricity become prohibitive in terms of its overall effect on the profitability of producing the next unit of output.

3.2 Dry year/wet year risk premiums

We noted in the section above that variability in hydrological conditions has the potential to impact on spot prices for electricity, and depending on the formula for price, on the cost to the user for purchasing electricity. New Zealand's electricity market is dominated by electricity produced from hydro generation (over 60%) and as such, significant variations in the level of water available for generation can impact on the spot price for electricity.

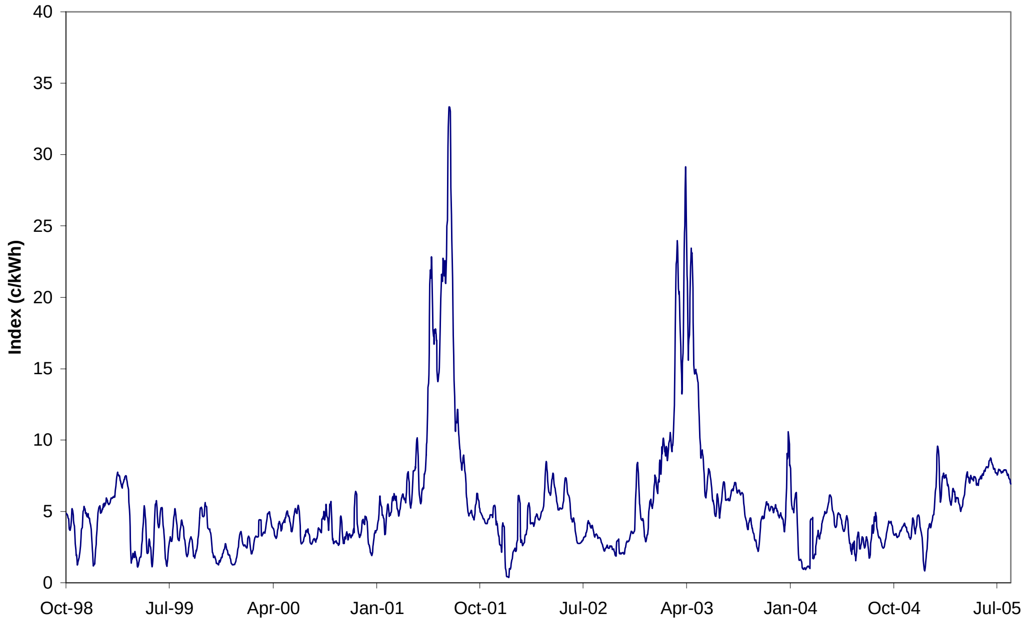
In recent years users have seen significant price spikes as a result of 'dry' (in hydrological terms) years. Both 2001 and 2003 produced dry years, where prices

[5] http://www.stuff.co.nz/stuff/0,2106,3491477a13,00.html – 26th November 2005.

rose to nearly 35c/kWh on the Electricity Price Index.[6] These are shown in the figure below.

Figure 4 Electricity Price Index

Seven day rolling average



Source: M-Co, the Marketplace Company Ltd.

As well as the potential absolute level of price change, it is also useful to consider the relative effects on the spot price of dry years compared to wet years. Table 1 below looks at the effect of both dry and wet years compared to 'normal' years in terms of hydrology. It uses the period from January 1995 to September 2004 to show the average February, March, April and May spot prices, excluding dry years (i.e. 2001 and 2003). It then uses the 2003 dry year and 2004 wet year prices for February, March, April and May to show the effective price premium and discount created from the dry and wet years respectively.

The dry year creates a significant wedge or premium above the normal year conditions. On average over the months shown, the wedge is over 200% i.e. the dry year price is over 3 times as large as the normal price.

When we look at the wet year discount though, we observe the asymmetry that exists between dry year spot price increases, and wet year price decreases. On average, over the months shown, the 2004 wet year discount was just over 20% i.e. the wet year price is only around 75% of the normal year price.

While this is only indicative and representative (it only looks at one dry and wet year for one (reference) node) it still indicates quite strong asymmetry in price. In dry years the spot price looks to increase significantly more than it decreases in wet years. This high level of volatility in dry years could flow through to produce

[6] Seven day rolling average price. The EPI smoothes out the effect of week-end drops in price and short term price spike caused by temporary line and generating plant outages.

significant fluctuations in users' contracts, again depending on the particular price formula used in the contract.

Table 1 Dry/wet year price asymmetry

Averages cover the period January 1995 to September 2004 (Haywards node)

Haywards Prices	'Normal' year average	Dry year (2003)	Wet year (2004)	Dry year premium	Wet year discount
Average February price excluding dry year	4.0	8.5	1.5	116%	-61%
Average March price excluding dry year	4.4	15.4	2.8	252%	-36%
Average April price excluding dry year	4.4	19.9	4.6	355%	6%
Average May price excluding dry year	4.6	13.4	4.5	194%	-2%

Notes: (1) Premium and discount reflect the percentage change between the 'normal' year average for that month and the dry year/wet year

Source: NZIER

As with other risk, a generator who is willing to absorb this risk is likely to require a price premium to account for the risk they believe they may face from hydrological conditions.

For a user, consideration of the benefits/costs of being exposed to the effect of dry/wet years on the price they pay for electricity will be affected by (but not limited to):

- The way their price/price formula is affected by volatile prices. The price may be a yearly average of spot prices, percentage change from one year to another, a fixed price etc. Dry/wet year effects will vary depending on how the price is calculated. Some formula will smooth the effect of variability more than others. The asymmetry present means that users should be aware of the ability of smoothing variables to account for dry years vs. wet years.
- The share of electricity that is bought via the spot market.
- The 'risk appetite' of the user e.g. are they risk averse and if so, to what degree?
- The share of electricity costs as a factor of production.

The Electricity Commission has a role in helping to manage dry year security, and has also introduced mechanisms such as the Whirinaki 150MW plant to offer in electricity to the market when prices reach a 'trigger'. Both generators and users will need to consider the effect of such mechanisms on the volatility of prices that could still exist, and how protracted such volatility is. Again, the way in which the price paid is calculated (e.g. average, fixed price etc.) is vital.

3.3 CPI/PPI variations

A factor that is typically explicit in contracts for the purchase of electricity is a price escalation factor. This is usually to allow for a general change in the level of prices in the economy, which will in part be a result of changes to costs involved in the supply of electricity. They are typically applied quarterly or annually.

The two main price escalation factors used in electricity contracts are the Consumers' Price Index or CPI and the Producers' Price Index or PPI. The CPI is a "measure of the price change of goods and services purchased by private New Zealand households".[7] The PPI is a "measure of the change in the general level of prices for the productive sector of New Zealand".[8] For the PPI, two separate series are produced; PPI outputs (i.e. changes in the general level of output prices for the productive sector) and PPI inputs (i.e. changes in the general level of input prices for the productive sector). For the CPI, the series can be broken down into various product groups, and for the PPI the series is available for different industry groupings.

The rates of change in each of the indexes are typically referred to, rather than the index values themselves for ease of interpretation.

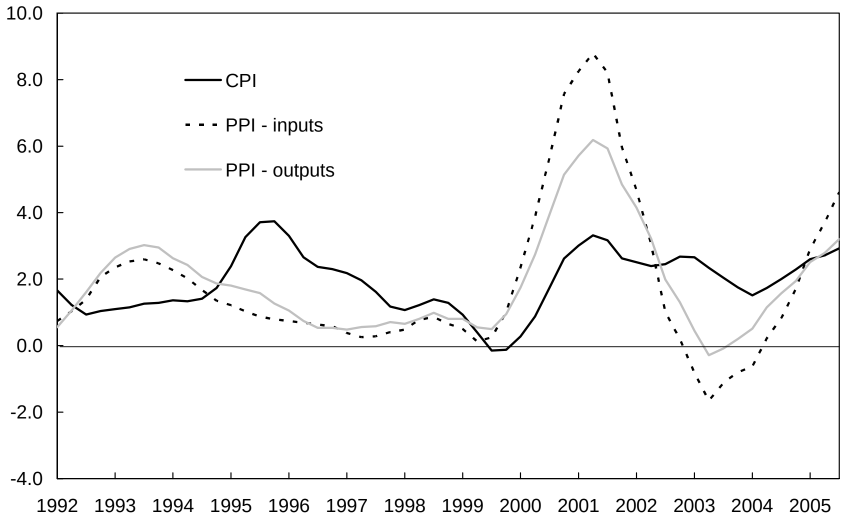
The figure below indicates the annual average percent change in both the CPI and PPI (inputs and outputs). It highlights the relatively low levels of volatility compared to the potential variability of other final price components such as the cost of production and the effect of a dry year. The inclusion of a price escalation factor based on the PPI though, is likely to have a larger impact than one using the CPI though, given historical variations in the index.

[7] http://www.stats.govt.nz/products-and-services/info-releases/cpi-info-releases.htm

[8] http://www.stats.govt.nz/products-and-services/info-releases/ppi-info-releases.htm

Figure 5 CPI and PPI (inputs and outputs)

Annual average percent change (aapc)



Source: Statistics New Zealand

There are advantages and disadvantages in using the CPI or PPI, however the volatility (and hence the risk) that they introduce into typical contracts is not large. It again depends on the formula or calculation of price and how the price escalation factors is included. Some contracts will only use a proportion of the CPI/PPI effect, while others may have a limit on how much of the CPI/PPI is included. However, even relatively large CPI/PPI changes could easily be outweighed by general spot price volatility (particularly in the presence of a dry year).

3.4 Nodal price risk

The New Zealand electricity market is based on a nodal pricing system (sometimes called locational marginal pricing or LMP) whereby every half hour there is potentially a different price at each of approximately 250 nodes around the country.[9] Two key 'reference nodes' are often used in the industry; the Haywards (North Island) and Benmore (South Island) nodes.

The differences in price between nodes reflects the following factors:

- The marginal cost of generation required to meet demand;
- The marginal costs of transmission system losses (some electricity is 'lost' from the system as it passes through the transmission system);
- The marginal costs of transmission constraints (whereby the transmission system restricts the electricity flow; through insufficient capacity or through a fault for example).

For each node, these factors are aggregated with the spot price to arrive at a total nodal price.

[9] NZIER report to the Electricity Commission, *Market Design Report – Initial Stock-take Paper*, August 2005, p.83.

As well as the variation in the underlying spot price, the factors outlined in the bullet points above can contribute to marked difference between nodal prices, but also to significant spikes in prices for a particular node over time. A fault on a particular section of the transmission network can result in restrictions on the amount of electricity available to users on that section, and hence the price for the electricity available can spike i.e. the prices on either side of the constraint reflect the effect of the constraint on the ability to deliver energy to each point either side of the constraint.[10]

A prime example of a transmission constraint affecting nodal prices is the HVDC link between the North and South Islands. The HVDC cable acts as a link between the islands to primarily transport electricity generated in the South Island, to users in the North Island. Flows in the other direction also occur, but not to the same extent. When there is a fault on the HVDC, this restricts the flow of power from the South to the North Island. As a result, the 'trapped' electricity effectively creates a surplus in the South Island and a deficit in the North Island (although in reality demand and supply are always in balance). As a result, we see prices drop at South Island nodes, and rise at North Island nodes – sometimes called price separation.

An additional effect resulting from constraints in the transmission system which could affect prices faced by users are so called 'spring washer effects'. The effect is characterised by prices rising significantly, and sometimes exponentially, around nodes in a transmission loop when a constraint binds on one part of the loop.[11] Essentially, this means that nodal prices can be created which are far in excess of the actual price of individual generation offers. The Electricity Commission[12] identified a number of features which are present when a spring washer effect occurs:

- There is a binding constraint on one leg of a transmission loop;
- Low priced generation downstream of this constraint is constrained; and
- There is also higher priced generation within the unconstrained leg of the loop that is able to be dispatched.

Essentially, in a situation where there is a network loop, the electricity can take more than one path, and higher priced generation is required to be used at the expense of lower priced generation which is 'backed-off' to determine the flow of electricity around the constraint. The marginal cost at the node (i.e. the nodal price) is the cost of generating the unit at the node plus the incremental costs of all the units at the other nodes where cheaper generation had to be backed off. The resulting price spikes can be considerably higher than the price being offered by individual generators, with the effect being substantial and aggravated as each additional unit of demand is added.

[10] http://www.electricitycommission.govt.nz/pdfs/advisorygroups/wmag/15sep05/5Spring-wash-pricing.pdf

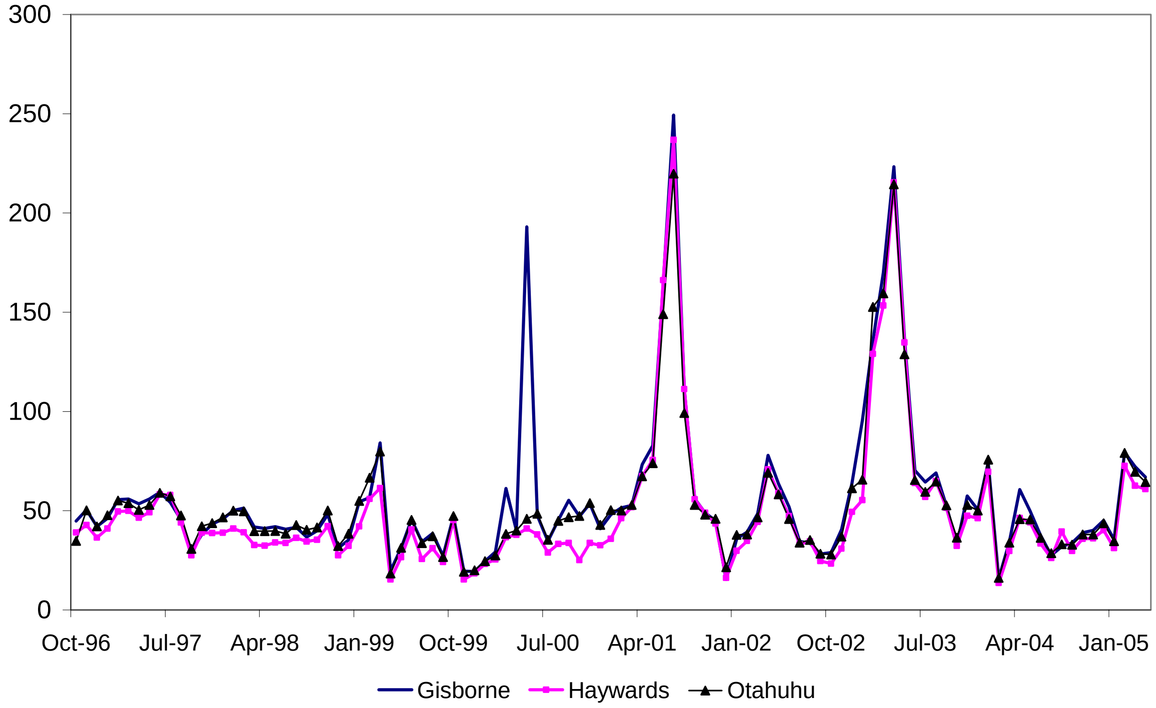
[11] Information on spring washer effects has been obtained from a draft Electricity Commission consultation paper entitled *"Consultation paper: High Spring Washer Pricing"*, 2005, Draft for WMAG review. It can be found at:
http://www.electricitycommission.govt.nz/pdfs/advisorygroups/wmag/15sep05/5Spring-wash-pricing.pdf

[12] ibid.

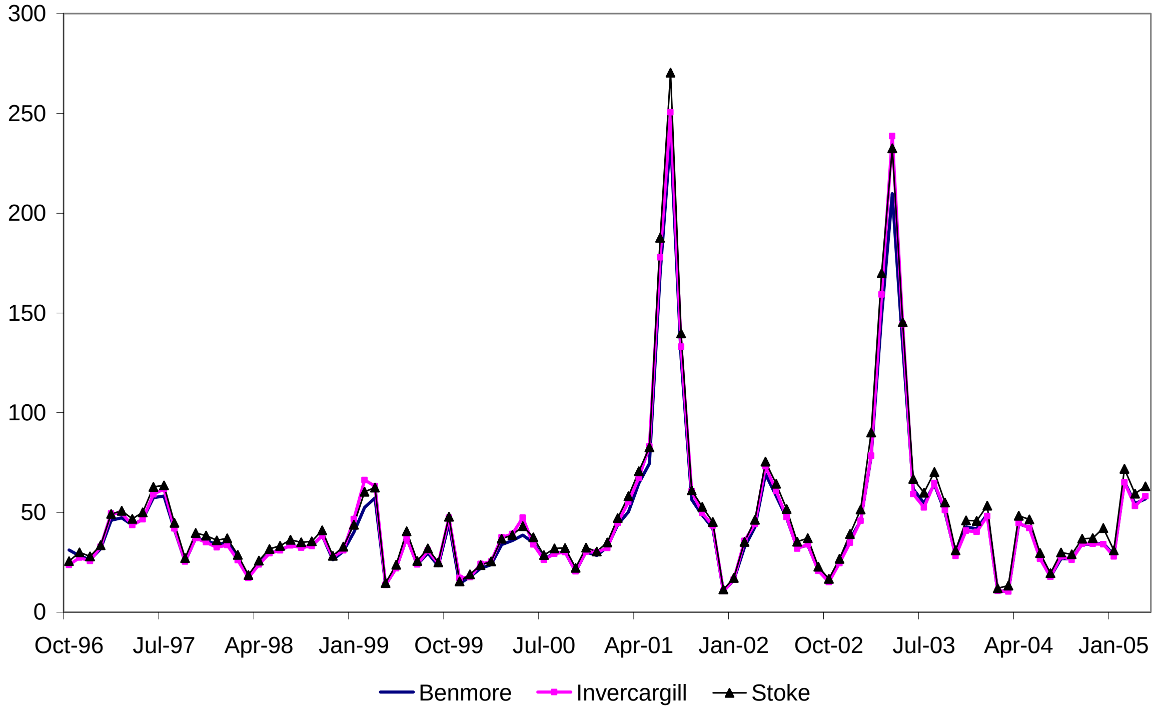
The figures below show monthly average spot prices at a small selection of key nodes around the country. They clearly highlight the potential variations in situations where the underlying spot price changes (such as the dry year spikes in 2001 and 2003) but also through effects specific to that particular node, particularly transmission constraints.

Figure 6 Monthly average spot prices ($/MWh at key nodes)

Gisborne, Haywards and Otahuhu nodes



Benmore, Invercargill and Stoke nodes



Source: Electricity Commission

The relative impacts of volatility in transmission constraints and transmission losses in also important to note. Transmission system losses are reasonably predictable and do not tend to create significant spikes. Transmission constraints, however, can cause significant nodal price variation, and are difficult to predict. Users could look to assess risk from historical price information as to how often constraints are likely to have caused spikes in their nodal price. However, as the transmission system and the energy flows across it are dynamic, historical levels cannot be relied on in isolation as indicators of future prices Consideration needs to be given, for example to information provided by Transpower about its system upgrade intentions (through the Grid Upgrade Plan Transpower is required to prepare) to investigate the potential future level of constraints.

In terms of the burden of risk for nodal price variations, a supplier of electricity to a user will require a premium to cover the potential effects of transmission constraints and system losses. It is likely that the premium would relate to risks specific to the node which feeds the user. In some cases, generators can create 'natural hedges' by locating plant close to a retail customer base, or contracting with other local generators for risk cover (horizontal hedges) hence reducing the potential effects of significant variations in price.

3.5 Carbon tax effects

We noted earlier in section 3.1 that the Government had, until very recently, been set to introduce a carbon tax on greenhouse gas emissions from the combustion of fossil fuel from 1st April 2007. This would have impacted primarily on those using coal and natural gas for the purposes of generating electricity. The charge would have essentially been a tax on the fuel, and as such would have resulted in an increase in the cost of producing electricity from the use of these thermal fuels.

The tax was to have been introduced at a level of \$15/tonne CO_2 for the first commitment period, and would have only increased if the international price of carbon exceeded \$NZ15/tonne equivalent for a sustained period.[13] The Government has recently announced that the tax will **not** be introduced as planned, with reasons being that "rising oil prices had already partly achieved the intended effect of the tax in the transport sector and officials had advised the tax would not cut emissions enough to justify its introduction".[14] The release from the Government did note though that a more narrow tax which would be targeted at major electricity users and the electricity generation sector was still likely. It also suggested that a broader carbon tax could again be considered after 2012.

In terms of the allocation of risk, we understand that in general the carbon tax element of a contract has tended to be isolated as a separate component due to the uncertainty around the exact level of the tax. This means that the cancellation of the tax should be relatively easily handled in existing contracts.

The raising of the possibility of an alternative charge highlights the importance for users of identifying whether any allowance for a carbon charge is included in their existing contracts. For new contracts, users should ensure that the possibility of a carbon charge being introduced is allowed for, whereby good faith negotiation of how the charge should be included can occur, if a charge is introduced. It should be clear that the negotiations should not unfairly disadvantage either party e.g. if a generator is a beneficiary from the carbon charge, then the user cannot be

[13] It was to be capped at a maximum of \$25/tonne CO_2

[14] http://www.stuff.co.nz/stuff/0,2106,3519195a10,00.html – 21st December 2005.

expected to pay for the charge. The condition should also allow for a process to resolve any disputes about how any carbon tax that was introduced should be incorporated.

3.6 Plant outages and force majeure

Users of electricity can potentially be exposed to high spot prices through their contracts via force majeure or plant outage clauses. Typically, these clauses are separate and distinct from other components relating to the price of electricity.

A force majeure event relates to an unforeseeable and unavoidable event, outside of the control of the defaulting party to the contract, which means that the contract cannot be met. Sometime such events are referred to as "acts of God". Generators include these clauses as protection against such an event. They are commonplace in contracts for electricity.

Plant or generation outages relate to times when the plant is unable to generate (such as for maintenance), and hence the contract cannot be met (in terms of supplying electricity to the user). This can potentially expose the generator (or retailer) to high prices if they are required to purchase electricity from the spot market to meet their obligations. Some contracts include suspension clauses to allow for such plant outages.

While there is a clear difference between a situation which relates to a force majeure event and a plant outage, there are some cases whereby contracts allow for suspension outages to be considered as force majeure events. Indeed, a recent study of contracts for the Major Electricity Users Group by NZIER found that:

"The force majeure and suspension clauses that are included in some New Zealand electricity hedges…allow sellers to default if their own power stations are not generating or cannot be dispatched. Default is not unavoidable in these circumstances and hence these cannot be considered FM events"[15]

Users should ensure that their contracts are clear in their definition of what is a force majeure event (i.e. unforeseeable, unavoidable, beyond the control of the defaulting party etc.) as opposed to a clause covering plant outages. They should also ensure that they are not taking on risk that could be more efficiently handled by the other party. They should ensure that they are not paying too much for the other party to take the risk, or that they are receiving an appropriate discount for taking on risk.

3.7 Market levies and other costs

There are costs associated with being a market participant which the person offering the contract will seek to recover from the user in terms of the contract

[15] http://www.nzier.org.nz/SITE_Default/SITE_Publications/x-files/10996.pdf *"Force Majeure in Electricity Hedge Contracts in New Zealand"*, April 2005, p.i.

price/pricing formula. The fees they are likely to be seeking to recover will include:[16]

- A standard levy, which also covers access to COMIT, the market electronic information system;
- The costs of providing bids for each half-hour, although this can be contracted out; and
- The costs of supplying prudential security to the clearing manager if the firms long term credit rating is below Standard & Poors A- or the equivalent from another rating agency.

The Electricity Commission also imposes fees on market participants to cover the costs of its operations, and for the purchase from service providers of ancillary services, such as, reserves. The levy imposed on market participants is different for generators, retailers, lines companies, and the transmission operator (Transpower).[17] The Electricity Commission does not charge the levy to consumers of electricity directly unless those consumers are large enough to be market participants in their own right, but the amount effectively paid by the consumer will depend on the how much of the charge is passed through to individual consumers by retailers for example.[18] These costs are likely to be outlined separately in a contract.

If the consumer is a market participant they will buy electricity at the spot price from the market clearing manager and hold hedge contracts to mange price volatility risk. Under these circumstances the consumer will pay Electricity Commission levies and fees directly, which will include additional items such as the cost of Whirinaki reserve generation. Under this contract structure these items are unlikely to be identified in the contract document.

3.8 Credit risk

As we noted above, a market participant is required to supply prudential security to the clearing manager based on credit rating minimum requirements. The participant would look to recover a proportion of such costs in a contract with a user. In addition, the person offering the contract (whether it be a generator or retailer) also faces the credit risk of the customer i.e. if the customer defaults. Given this, the generator or retailer is likely to include a premium (and possibly other conditions) to cover for its assessment of the credit risk of the party being offered the contract. It is important that consumers are aware of the cost of credit risk they are being charged and options for minimising this risk.

[16] NZIER report to the Electricity Commission, *Market Design Report – Initial Stock-take Paper*, August 2005, p.46.

[17] http://www.electricitycommission.govt.nz/opdev/levies

[18] ibid.

3.9 Regulation and government risk

Another component of the effective price paid by the user for electricity will relate to the generator or retailer's perceived risk of regulation, and its impact on the cost of supplying electricity to consumers.

Given the relatively recent introduction of the Electricity Commission, and the existing and potential involvements of other regulatory bodies in the industry (such as the Commerce Commission), participants will have formed a view about what potential risk they face in terms of carrying out their operations. They are likely to include a premium in the price to allow for this risk to be mitigated.

The websites of the regulatory bodies provide regular and fairly comprehensive updates on movements in the industry, such as papers from working groups and consultation documents. These will be useful for users to monitor. Users should make use of opportunities to provide comment on industry issues, as most significant changes require consultation with market participants and/or affected (or sometimes interested) parties.

3.10 Other points for consideration

The discussion so far has concentrated on just the energy price components involved in typical electricity contracts for large users. For a number of large users who are not direct connects, transmission and distribution charges are likely to represent material proportions of the total cost of being supplied electricity. For these users, there are some additional points for consideration in existing contracts, and when investigating new contracts.

The first relates to the passing through of transmission and distribution charges to the user. A user with a contract with the distribution network (i.e. does not buy the distribution service through a retailer) will be paying the distributor for both transmission and distribution charges. While it is appropriate that they pay for the transmission costs associated with delivery, they should investigate whether the distributor applies any margins to the transmission charge. Just how explicit the charges are will vary by contract, and will be less explicit if transmission and distribution charges are bundled together. For those users purchasing distribution services via a retailer, they should investigate whether any margins are applied to both transmission and distribution charges. Again, just how explicit these charges are will vary and many may be bundled together, making the identification of margins more difficult.

Where investments have been made to the distribution and transmission system, the allocation of the investment costs may form part of the charges faced by consumers. How these investment costs are justified and allocated should be reviewed and if necessary challenged.

The second issue relates to the pass through of loss and constraint rentals. These rentals are paid by Transpower to the distribution companies. Users should investigate and be aware of the magnitude of the rentals being passed through to their distribution network, and whether they are being allocated their share via the distributor/retailer. Users could expect an explicit payment for their share of the rentals, or an appropriate reduction in the price they pay for electricity. For some users, these rentals may appear as a separate line item in their charges, but for others they may be less explicit. Those considering new contracts may wish to have such rentals explicitly itemised.

4. Summary of components and their impact

The sections above have outlined the key typical contract components that are likely to feature – either explicitly or implicitly – in contracts for the purchase of electricity by non-residential users.

We have highlighted what the key components are, the risk that surrounds them depending on the party holding the exposure, and have identified key issues for parties to consider when looking at their own existing/new contracts. While some components present low levels of risk regardless of the party holding the exposure, others are potentially more volatile, and hence the importance of understanding the magnitude of risk present in all contracts is high.

The table below summarises the information from the sections above, by listing each component, its potential to impact on the total price, the relative effect on the total price if it does occur, and issues for parties to consider in terms of their own contracts.

Table 2 Contract components and their impact

Component of total contract price	Risk of impacting on total price	Impact on price if occurs	Issues to consider
Cost of production	High	High	Fixed price offers will need to cover generators variable costs. Will take account of opportunity cost (selling on spot market) and consideration of risk around production costs. Users should make own assessment of these factors and risks for comparison of prices and risk from buying on spot vs. contract. Depends if formula in contract contains spot price element or is fixed.
Spot price variability	High	High	Risk depends on formula for price, but few opportunities to avoid spikes if user takes exposure. Very dependent on firm structure, output, margins etc. but potentially large impact.
Dry/wet year variability	Uncertain	Very high	Uncertainty around likelihood but potentially huge impact if dry year occurs and user has exposure. User needs to consider asymmetry of dry/wet year risk and impact on their pricing formula. Generator/retailer will require margin to cover risk.
CPI/PPI price escalation	Depends on contract	Low	Relatively low impact if included in contract, compared to other components such as dry year risk and spot price variability. Commonly used measures for general price escalation.
Nodal price risk	Depends on node	High	Dependent on constraints for particular node, potential for high volatility. User should consider likelihood of constraint, upgrades planned, and potential shocks to price from constraints binding.
Carbon tax effects	Uncertain	Uncertain	Planned carbon charge cancelled. Possibility of alternative charge still focussed primarily on gas and coal fired generation. Users should allow for good faith negotiations for inclusions in contracts if carbon charge re-emerges, ensuring no disadvantage to either party. Allow for dispute process if negotiations fail.
Plant outages and force majeure	Uncertain	High	Users should ensure that these components are made separate and distinct as a plant outage and a force majeure event are not the same.
Market levies and other costs	High	Low	Costs are generally known and not volatile. Relatively little impact.
Credit risk	High	Depends on user	Risk is highly dependent on generator/retailers assessment of user risk. Effect not volatile unless prudentials called upon.
Regulation and government risk	High	Uncertain	Uncertainty around actual impacts which could result, but certainly much more focus on energy sector regulation in recent years. Unlikely to be alleviated in the near future. Use publicly available info. to keep updated on industry changes.
Margins on electricity delivery and loss and constraint rentals	High	Uncertain	Users should investigate any margins which may have been applied to transmission and/or distribution charges relating to their electricity supply. They should also investigate whether they receive their share of loss and constraint rentals which are paid to distribution companies. Users could expect an explicit payment for their share of the rentals, or an appropriate reduction in price.

Source: NZIER