# Results Presentation

**Financial year ended 30 June 2010**

20 August 2010

# Disclaimer

This presentation may contain projections or forward looking statements regarding a variety of items. Such forward-looking statements are based upon current expectations and involve risks and uncertainties.

Actual results may differ materially from those stated in any forward-looking statement based on a number of important factors and risks.

Although management may indicate and believe that the assumptions underlying the forward-looking statements are reasonable, any of the assumptions could prove inaccurate or incorrect and, therefore, there can be no assurance that the results contemplated in the forward-looking statements will be realised.

Furthermore, while all reasonable care has been taken in compiling this presentation, Contact accepts no responsibility for any errors or omissions.

This presentation does not constitute investment advice.

# Outline

# EBITDAF down $18m (4%) from FY09
# Wet conditions for most of the year; retail competition intensified

contact

- Retail electricity margins contracted from 5% to 2%
  - Volumes and customer numbers maintained
  - Sales revenue up $18m (2%)
  - Network, energy and retail costs up $48m (4%)

- Unit generation costs up 5%
  - 7% increase in underlying unit gas costs to $8.16/GJ
  - High hydro inflows, increased renewables

| Generation | FY10 | FY09 |
|---|---|---|
| Renewable | 60% | 55% |
| Thermal | 40% | 45% |

  - Gas storage helped mitigate consequential gas length
  - Residual take-or-pay gas costs: $24m (added a further 0.84/GJ to effective gas costs)
  - Contribution from exposed generation up $7m (higher volume, lower average price)

- Other (wholesale and retail gas/LPG) contribution up $7m
  - Retail gas margins improved during the year

| Key financial information | FY10 | FY09 | Variance | % |
|---|---|---|---|---|
| EBITDAF ($m) | 427 | 445 | (18) | (4%) |
| Profit for the Period ($m) | 155 | 116 | 39 | 34% |
| Underlying Earnings After Tax ($m) | 150 | 159 | (9) | (6%) |
| Capital expenditure ($m) | 469 | 492 | (23) | (5%) |
| Operating cash flow after tax ($m) | 323 | 314 | 9 | 3% |
| Net debt ($m) | 1,347 | 1,124 | 223 | 20% |
| Net debt / net debt + equity (%) | 32% | 29% | 3% | 10% |

# Statutory profit: $155m, up $39m (34%) from FY09

| NZ$ Millions | 12 Months Ended 30 June 2010 | 12 Months Ended 30 June 2009 | Variance $million | Variance % |
|---|---|---|---|---|
| EBITDAF | 427 | 445 | (18) | (4%) |
| Depreciation and Amortisation | (162) | (166) | 4 | 2% |
| Equity Accounted Earnings of Associates | 3 | 4 | (1) | (25%) |
| Change in Fair Value of Financial Instruments | 5 | (57) | 62 | 109% |
| Removal of New Plymouth Asbestos and Related Costs | (6) | - | (6) | |
| Impairment of Gasbridge Assets | - | (3) | 3 | 100% |
| Retail transaction processing outsourcing costs | (3) | - | (3) | |
| Net Interest Expense | (56) | (63) | 7 | 11% |
| Income Tax Expense | (53) | (44) | (9) | (20%) |
| Profit for the Period | 155 | 116 | 39 | 34% |

- Depreciation and amortisation expense was down $4m or 2% primarily as a result of the normal periodic review in useful life of assets
  - About $13m lower than anticipated at the time of the half year result (see slide 46)
- Net interest expense reduced by $7m to $56m
  - $48m of interest was capitalised for key projects (Stratford peakers, Ahuroa gas storage and Te Huka)
  - Net interest expense for FY11 is expected to be ~$90m as projects move into the operating asset base from capital work in progress
- Income tax expense up $9m – see next slide

# Underlying earnings after tax: $150m, down (6%) from FY09
# Distribution per share: 25 cents, down 11% from FY09

| | 12 Months Ended 30 June 2010 | 12 Months Ended 30 June 2009 | Variance | % |
|---|---|---|---|---|
| **Profit for the year ($m)** | 155 | 116 | 39 | 34% |
| Removal of New Plymouth asbestos and related costs (after tax) | 4 | - | 4 | - |
| Impairment of Gasbridge assets | - | 3 | (3) | (100%) |
| Retail transaction processing outsourcing costs (after tax) | 2 | - | 2 | - |
| Change in fair value of financial instruments (after tax) | (3) | 40 | (43) | (108%) |
| Change in corporate income tax rate | (43) | - | (43) | - |
| Removal of tax depreciation on buildings | 35 | - | 35 | - |
| **Underlying earnings after tax ($m)** | 150 | 159 | (9) | (6%) |
| **Earnings per share (cents)** | 25 | 27 | (2) | (7%) |
| **Distribution per share (cents)** | 25 | 28 | (3) | (11%) |

- **Key movements:**
  - **Adjustments for unusual items (increase in New Plymouth asbestos removal costs and retail outsourcing costs) - $6m post tax**
  - **$43m post tax positive movement in the change in fair value of financial instruments**
  - **Tax movement arising from the recent tax legislation impacting the deferred tax liability ($8m)**
- **Distribution per share: 25 cents/share, down 3 cents/share**
  - **Reflects FY10 performance – and the impact of high hydrology**
  - **Represents 100% payout for FY10**
  - **Adjustment is consistent with prior signalling**

# Significant progress was made on the delivery of Contact's strategic initiatives

- **Projects under construction:**
  - Te Huka Geothermal Power Station: completed early, below budget and operating above expected capacity
  - Stratford Peakers: Commissioning progressing
  - Ahuroa Gas Storage:  Gas injections continue. Construction of gas processing facilities progressing on schedule

- **Projects in development:**
  - Te Mihi (geothermal): Construction tendering
  - Taheke (geothermal): Mobilisation for drilling
  - Tauhara  2 (geothermal), HMR (wind) and Waitahora (wind): Consenting progressing

Te Huka

Stratford

Ahuroa

# Contact's safety performance improved by 25% during the year

- The safety of our employees, contractors and visitors to any Contact site is the company's highest priority

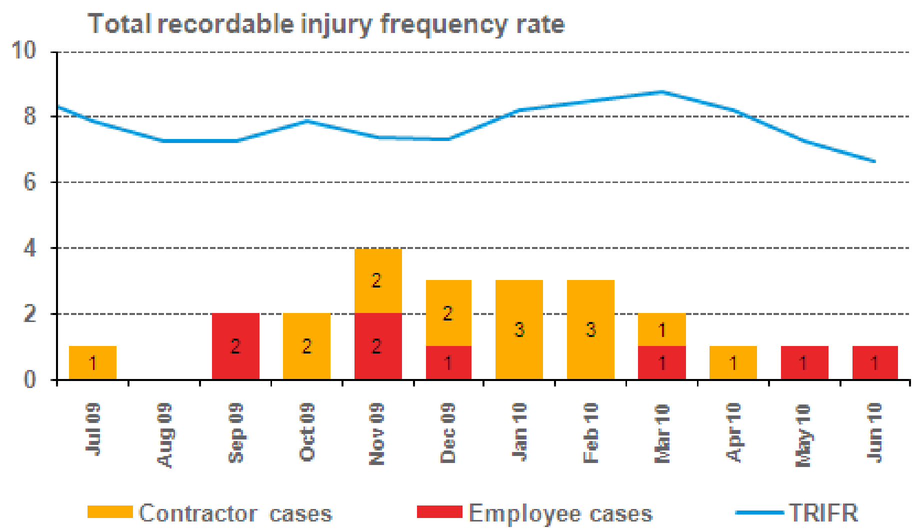
- Safety performance is measured in various ways

  Total recordable injury frequency rate (TRIFR)

  TRIFR: $\dfrac{\text{total number of recordable injuries}}{\text{million person-hours worked}}$

- In FY10, Contact's TRIFR improved 25% to 6.6

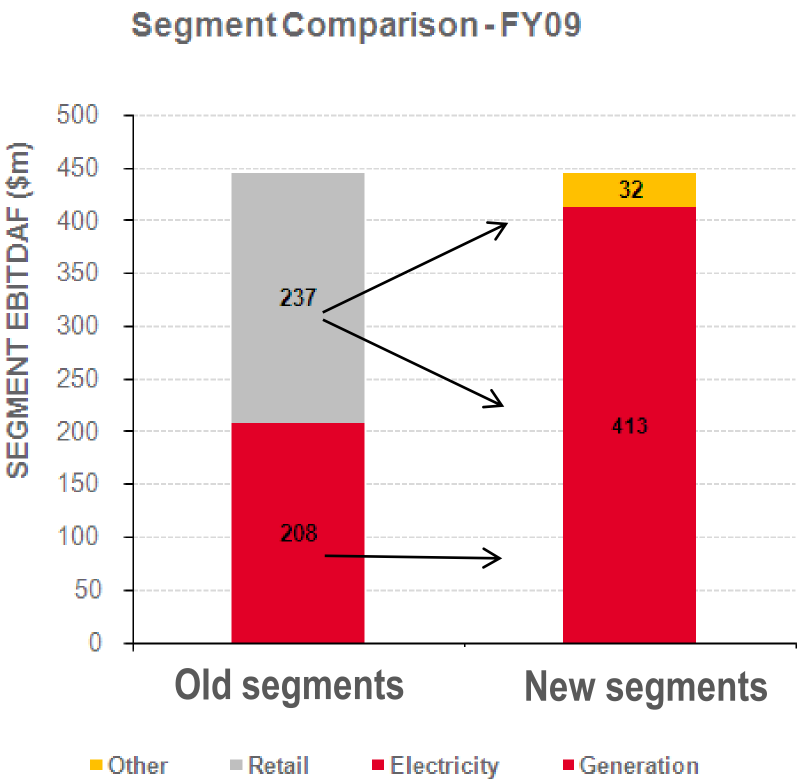
- Contact's aspiration is zero harm
  - FY11 safety goal: < 5.2



# Outline

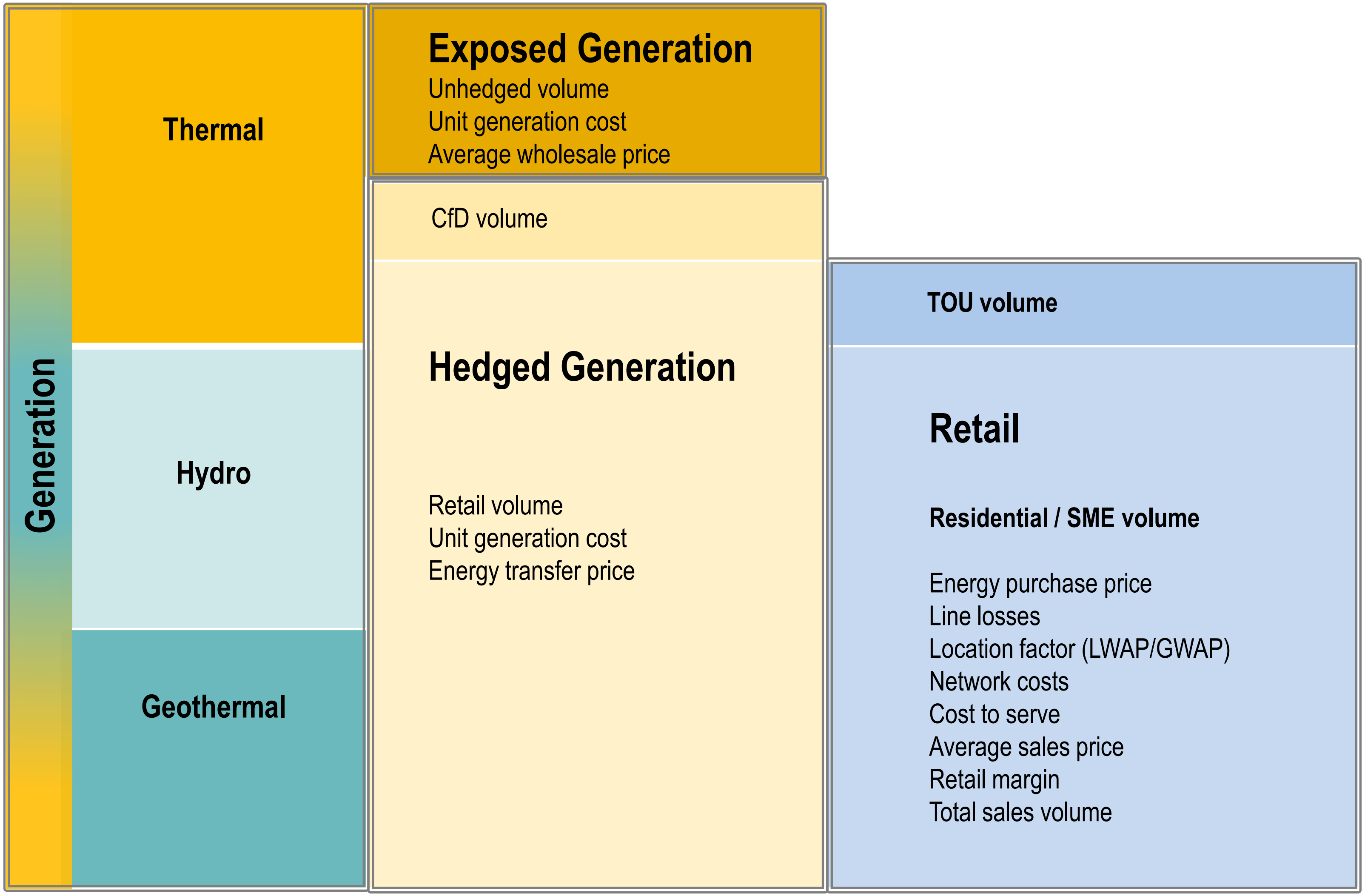
# Historically, Contact reported financial results based on the Retail and Generation segments. To improve the quality of financial reporting, Contact has established the 'Electricity' segment and the 'Other' segment

- Adopting an 'Electricity' segment better reflects the integrated nature of Contact's business
  - and removes the volatility in the prior segment results caused by wholesale price movements
- The 'Other' segment comprises retail and wholesale gas, LPG, meters and other revenue

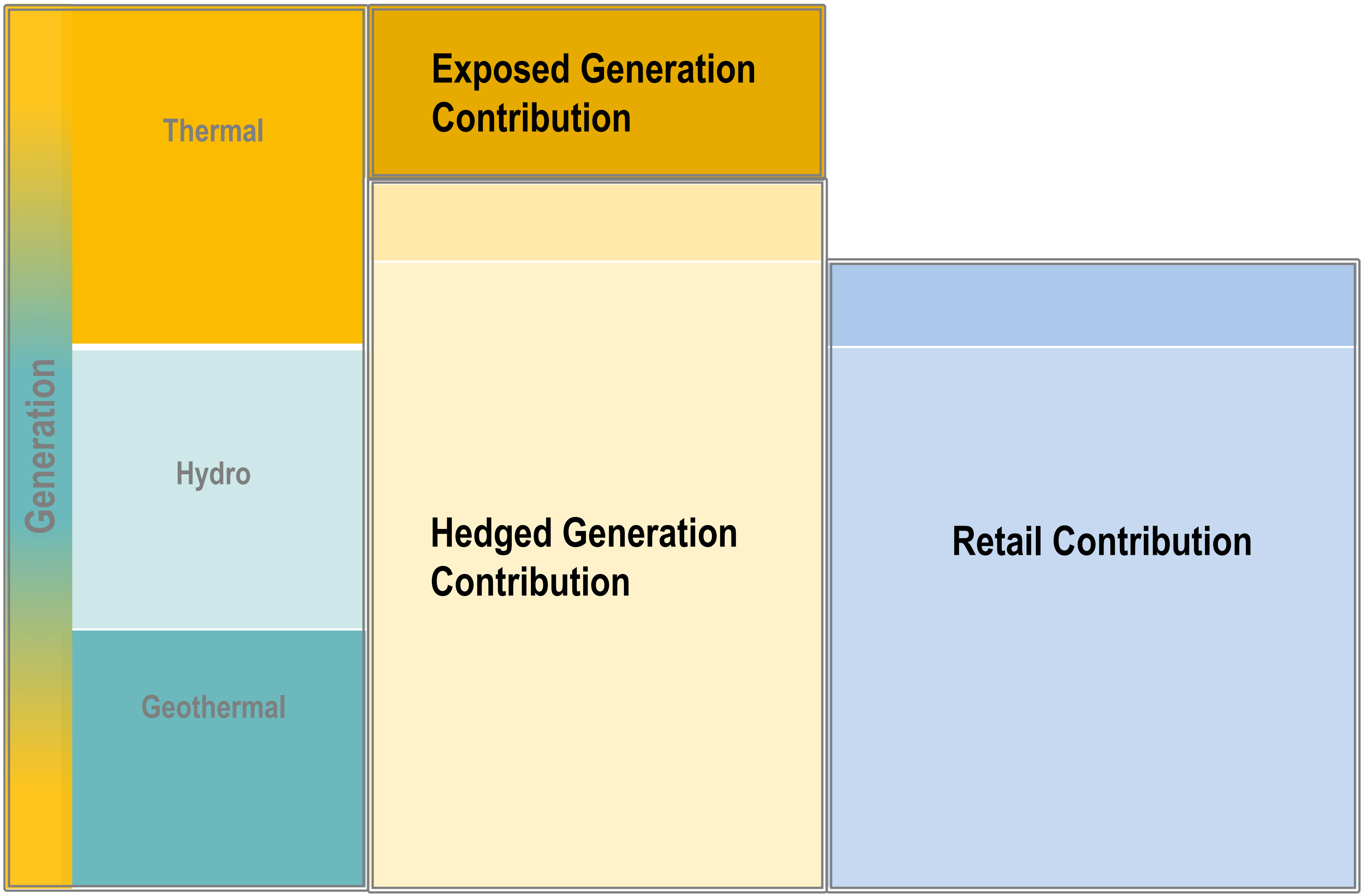


# The Electricity segment reflects the integrated nature of Contact's business

- **Contact sells its electricity generation through hedged and unhedged (exposed) channels**



# Electricity segment EBITDAF is the aggregate of contributions from Exposed generation, Hedged generation and Retail



# Electricity segment operational performance data (FY09 in parentheses)

**Generation: 10,183 GWh**

**Thermal**
**4,146 GWh (4,511)**
(including swaption)

**Hydro**
**3,760 GWh (3,543)**

**Geothermal**
**2,277 GWh (2,311)**

## Exposed Generation

Unhedged volume: 1,379 GWh (1,046)
Unit generation cost: $29.2/MWh (30.8)
Average wholesale price: $58/MWh (62)

CfD volume: 845 GWh (1,116)

## Hedged Generation

Retail volume: 7,959 GWh (8,203)
Energy transfer price: $80/MWh (76)

Unit generation operating cost:
$47.0/MWh (44.6)
(including LTMA costs: $54.2/MWh,
(50.1))

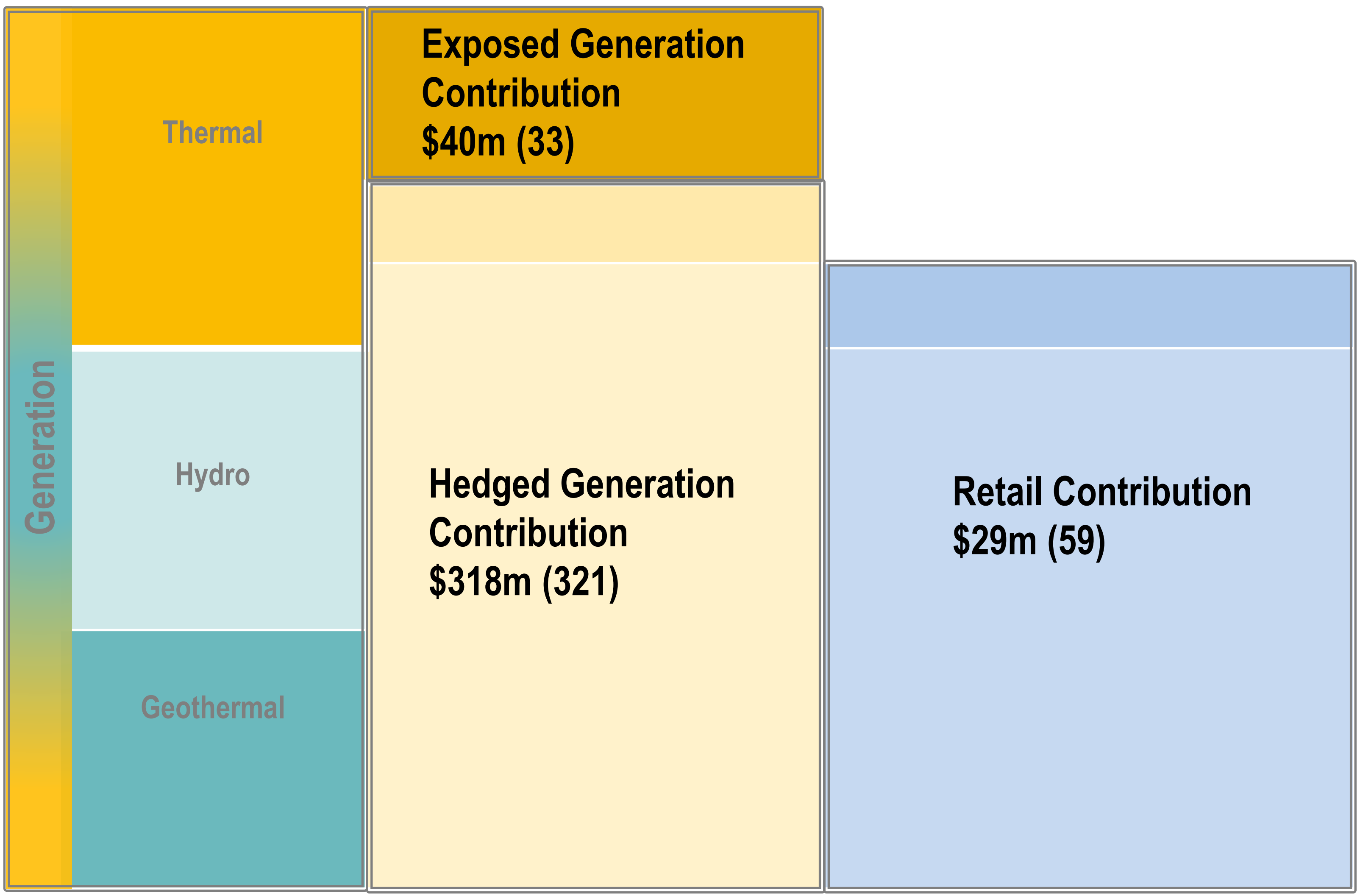
**TOU volume: 2,999 GWh (2,808)**

## Retail

**Residential / SME volume: 4,675 GWh (4,895)**

Energy purchase price: $80/MWh (76)
Line losses: 3.7% (6.5)
Location factor (LWAP/GWAP): 109% (109)
Network costs: $62/MWh (59)
Cost to serve: $15/MWh (14)
Average sales price: $170/MWh (167)
Retail margin: 2% (5%)
Total sales volume: 7,674 GWh (7,703)

# Electricity segment components show rising generation costs and retail margin compression (FY09 in parentheses)



# Segment performance

## Electricity segment EBITDAF: down $26m (6%) at $387m:

**Hedged generation:** Down $3m (1%) due to higher effective gas costs and lower volumes, offset by a higher transfer price and increased renewable generation

**Exposed generation**: Up $7m (21%) due to higher volumes offset by lower average prices and higher thermal generation costs

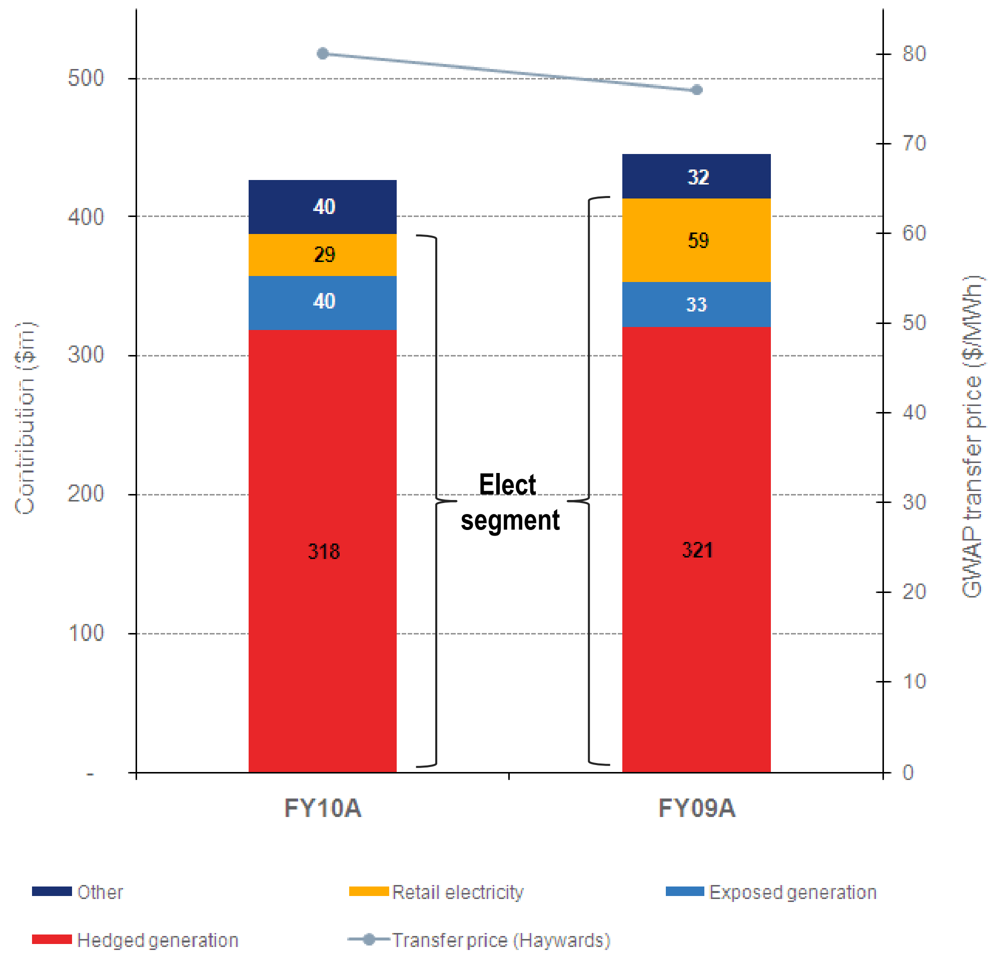
**Retail:** down $30m (51%) due to cost increases ($48m) exceeding revenue increases ($18m)

## Other segment EBITDAF: up $8m (23%) at $40m

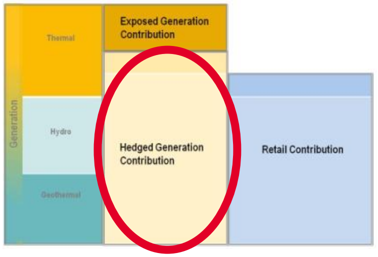
**Wholesale and retail gas** up $13m (135%)

**LPG** down $6m (43%) due to narrowing of margins

**Meters** up $1m (5%)



# Hedged Generation
## Down $3m (1%) due to higher generation costs and lower volumes



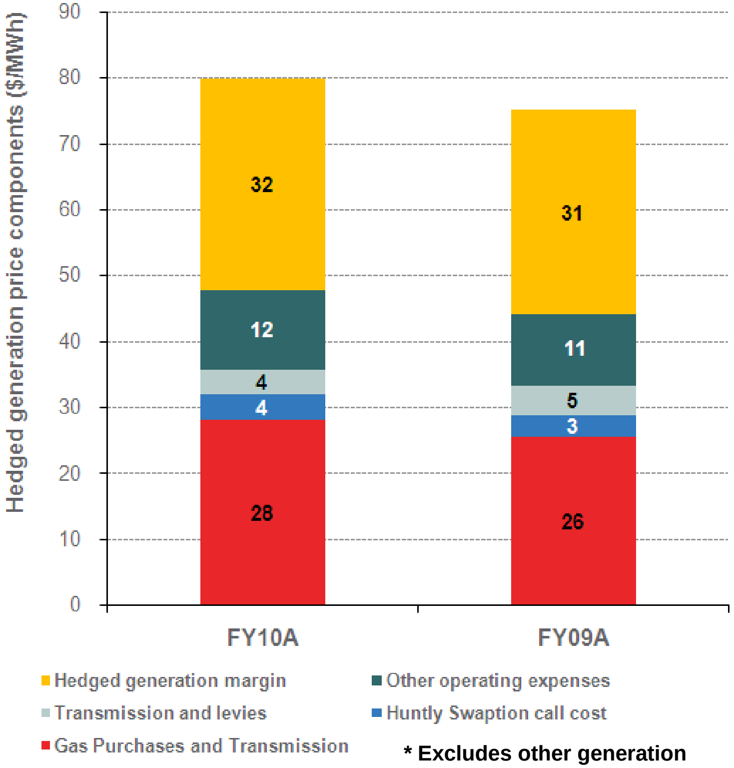

- Unit generation costs for hedged volumes up 7%
  - Underlying gas costs for hedged volumes up 14% to $9.80/GJ
  - Lower hedged volumes due to lower CfD volumes and lower line losses
  - Higher renewable generation

| Hedged generation | FY10 | FY09 |
|---|---|---|
| Renewable | 69% | 63% |
| Thermal | 31% | 37% |

  - Take-or-pay volumes up ~4 PJ to 52 PJ
  - Take or pay length of 4.7 PJ resulting in effective gas costs for hedged generation of $10.80/GJ ($24m gas cost impost)

- Higher generation costs resulted in a $4/MWh increase to the retail transfer price to $80/MWh
  - After capitalised CCGT maintenance (LTMA) costs are incorporated, hedged generation margins are $25/MWh
  - Hedged generation margin contributes to the cost of capital employed in generation assets

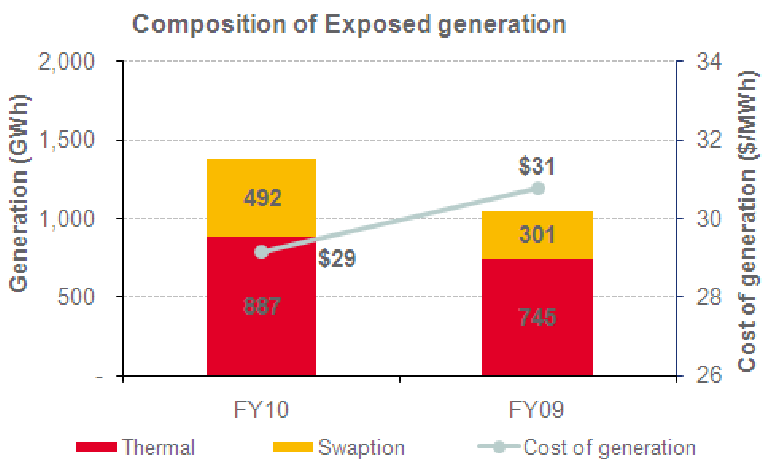
Breakdown of hedged generation contribution *

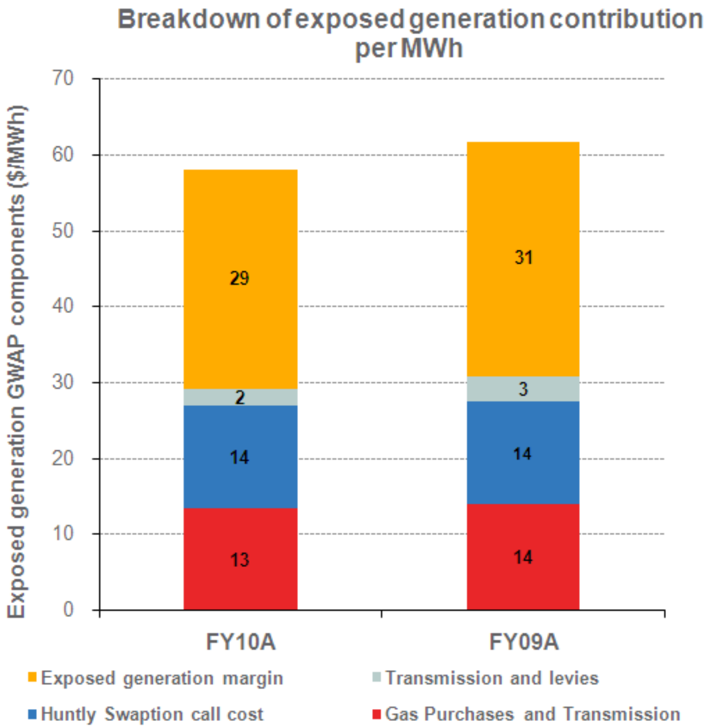



* Excludes other generation revenue

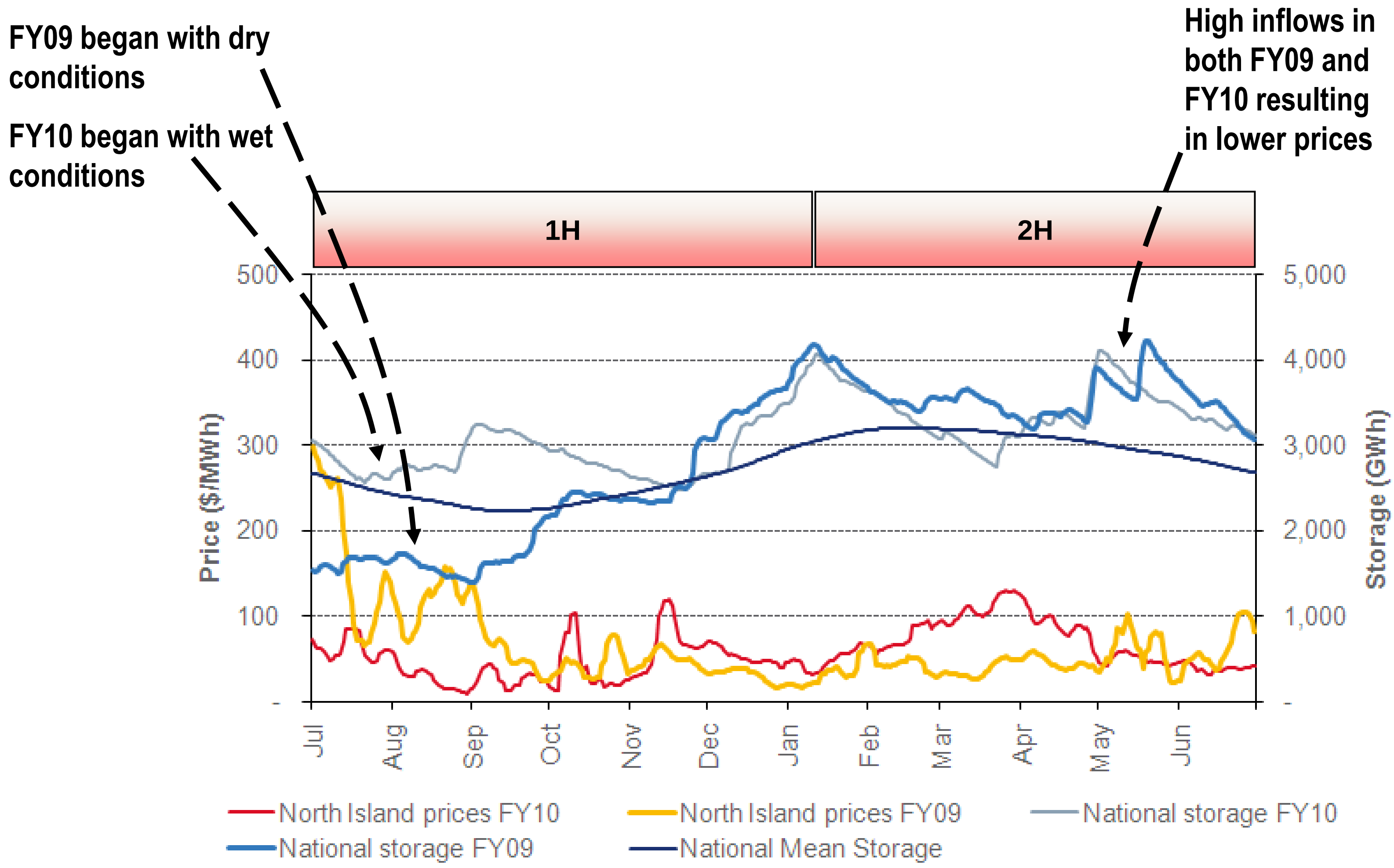

# Exposed Generation
## Up $7m (21%) due to higher volumes, offset by lower wholesale prices

- Exposed volume up 333 GWh (32%) to 1,379 GWh
  - About half of the potential volume
  - Low wholesale prices and extended maintenance CCGT outages constrained volumes
- Average wholesale price down $4/MWh
  - Another wet year



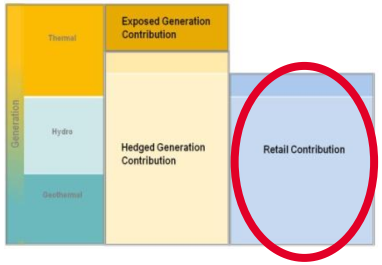



# Continuing wet conditions resulted in wholesale prices averaging $52/MWh, down $4/MWh from FY09



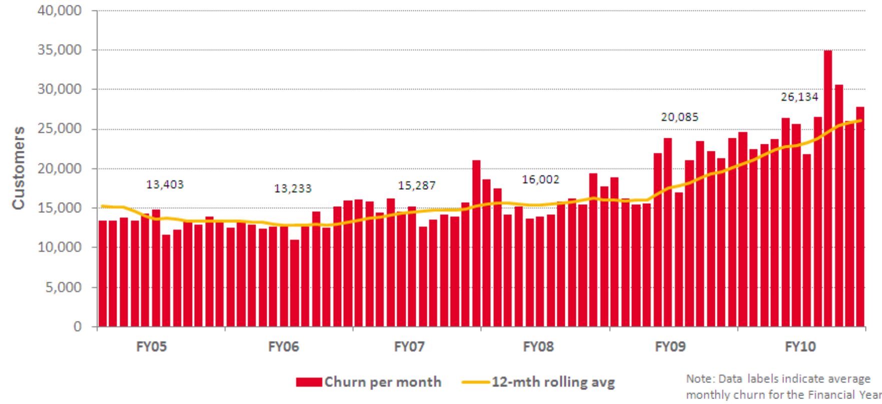
# Retail

## Down $30m (51%) due to higher costs in a low wholesale-priced competitive environment – resulting in margin compression

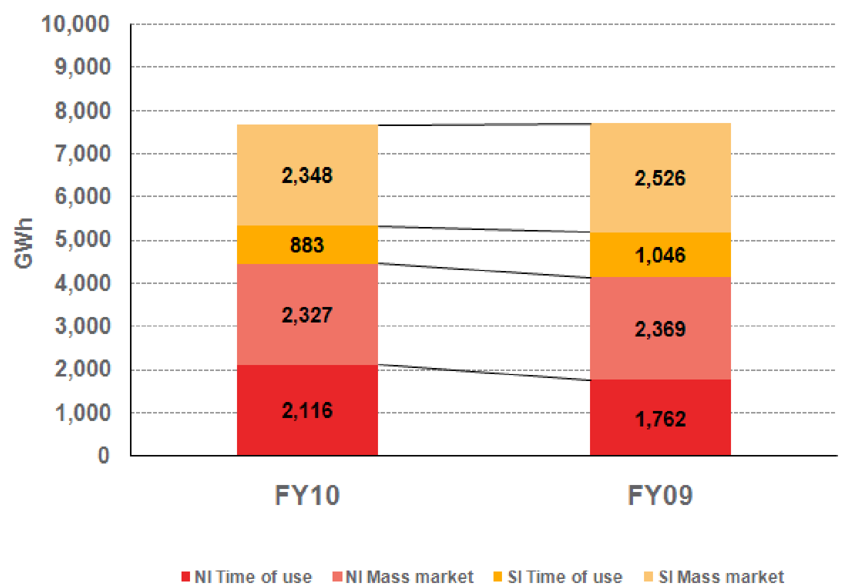



- **Maintained customer numbers and sales volume**
  - In spite of intense competition
  - Time-of-use load increased 7%
  - North Island : South Island load
    - FY10: 57% : 43%
    - FY09: 53% : 47%
- **Average sales price up 2% (revenue up $18m)**
- **Costs up 4% ($48m)**
  - Network costs up 0% to 22% (average: 5.7%, $27m)
  - Energy costs up 2% ($14m)
  - Other costs up $7m (higher churn)

Historic electricity market churn per month




Load split by customer type and island (sales)



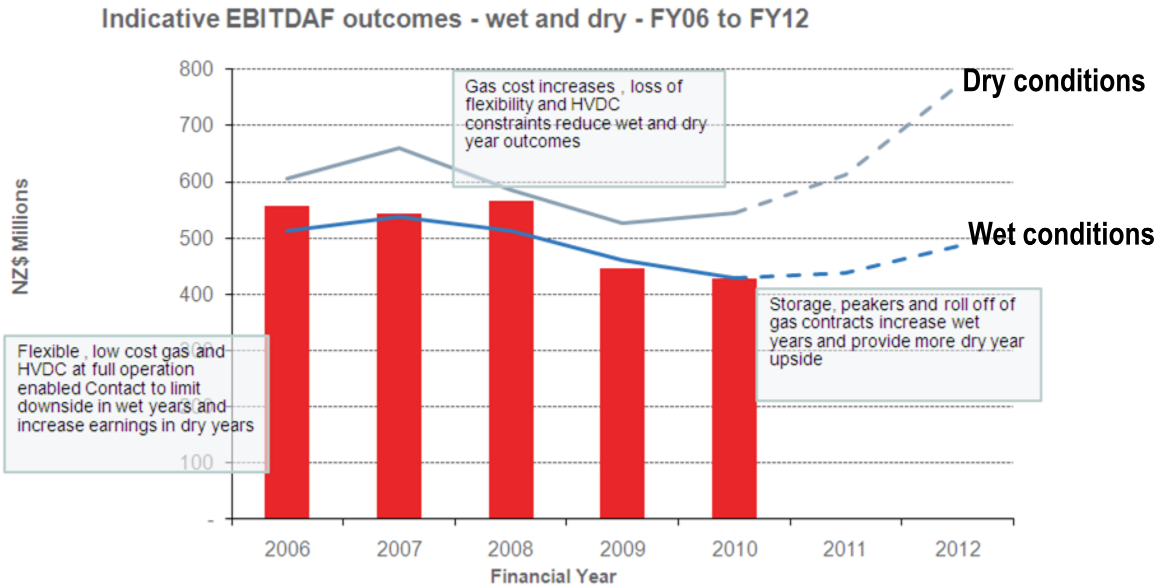
# "Other" segment contribution up due to higher retail gas margins, lower take-or-pay related gas sales losses and lower LPG contribution

- **Retail gas margin expansion was partially offset by higher gas costs and lower sales volumes**
  - **Average sales price up $3/GJ (16%)**
  - **Average gas cost up $1.20/GJ (7%)**
  - **Gas sales volumes down 0.7 PJ (18%)**
- **The reduction in LPG contribution reflects increased domestic LPG supply, increasing price-based competition**
  - **Sales volumes down 7k tonnes (9%)**
  - **Average sales price down $145/t (7%)**
  - **Average purchase prices down by $99/t (7%)**

| Other contribution | Units | FY10A | FY09A | Var | Var (%) |
|---|---|---|---|---|---|
| **Volumes** | | | | | |
| Wholesale gas | PJ | 10.7 | 11.1 | (0.4) | (4%) |
| Retail gas | PJ | 3.2 | 3.9 | (0.7) | (18%) |
| LPG | T | 70,327 | 77,082 | (6,755) | (9%) |
| **Contribution** | | | | | |
| Wholesale gas | $ 'm | (2.0) | (12.1) | 10.1 | 83% |
| Retail gas | $ 'm | 5.3 | 2.8 | 2.5 | 89% |
| LPG | $ 'm | 8.0 | 14.1 | (6.1) | (43%) |
| Meters | $ 'm | 18.7 | 17.8 | 0.9 | 5% |
| Other | $ 'm | 9.6 | 9.7 | (0.1) | (1%) |
| **Other EBITDAF** | **$ 'm** | **39.6** | **32.3** | **7.3** | **23%** |

# Outline

# Contact is emerging from an anticipated period of portfolio inflexibility which temporarily constrained the value of the portfolio's diversity




- **Until 2006, Contact's flexible and diverse portfolio was a key source of competitive advantage and earnings growth**
  - **Flexible, cheap gas supply arrangements; flexible generation; an unconstrained transmission system**
- **The value of the portfolio's diversity has been constrained by inflexibility – at a time when the operating environment required a great deal of flexibility:**
  - **Highly inflexible gas supply arrangements;**
  - **Inflexible generation – constraining the ability to respond to price volatility;**
  - **Transmission system constraints, particularly across the HVDC; and**
  - **Increasing price volatility due to increasing weather-dependent renewables and increasingly peaky demand**

# Investments to restore portfolio flexibility will be operational in late 2010 -  enabling fuel diversity and price volatility to be leveraged

**Stratford peaker project**

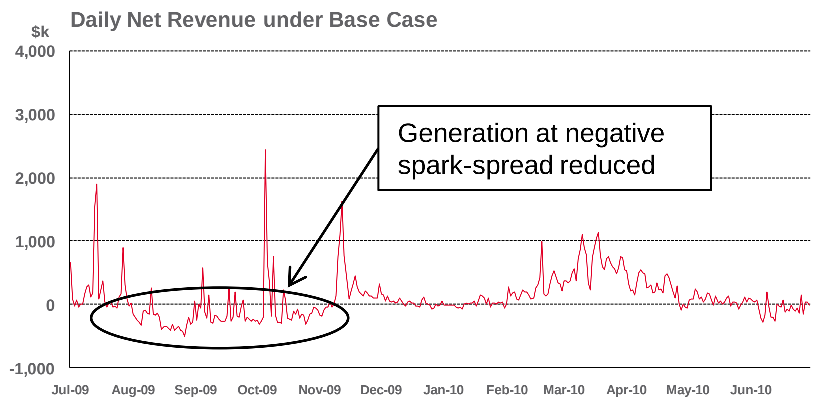
- 200 MW of flexible gas-fired generation
- Commissioning underway

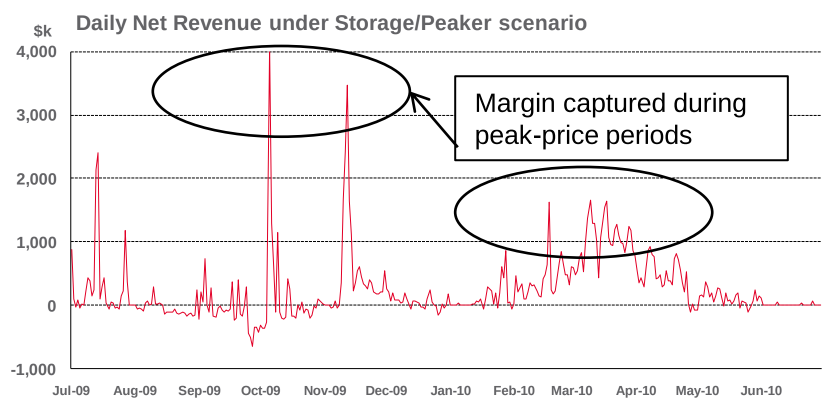
**Ahuroa gas storage project**

- Injection has recommenced following the reconfiguration of the compressor
- 5.2 PJ injected in FY10 (mitigating $33m of gas take-or-pay costs in FY10)
- Cushion gas is currently assessed as approx.  6.2 PJ; 5.2PJ of inventory gas as at 30 June 2010
- Well programme completed; facilities to enable extraction scheduled to be commissioned in early January
- Will operate at 32TJ/day injection and 45TJ/day extraction once commissioned

# If the Stratford Peakers and the Ahuroa gas storage facilities were fully operational in FY10, EBITDAF would have been up to $60m higher

- The volume injected would have increased from 5 PJ (actual injected in FY10) to 11 PJ
  - At an injection rate of 32TJ/day
- The peakers would have covered for CCGT outages and operated during peak periods
  - CCGTs would have been shut down during low-price periods



# FY11 will be a year of two halves

- **First half: Similar to 1H10**
  - **Wet conditions (current storage: 113% of average, current inflows: 150% of average)**
  - **Surplus take-or-pay gas**
  - **Average wholesale prices Sep-Dec: $54/MWh (EnergyHedge)**
  - **Retail competition to continue**

- **Second half: Portfolio flexibility expected to improve EBITDAF in both wet and dry conditions**
  - **Take-or-pay obligations lower from 52 PJ/y (CAL2010) to 40 PJ/y (CAL2011)**
  - **Lower take-or-pay gas levels and Ahuroa largely mitigate Contact's exposure to take-or-pay imposts in wet years**
  - **Lower take-or-pay gas levels, Ahuroa and the Stratford peaker enable the CCGTs to transition to mid-merit operation**

Stratford

Ahuroa

# Contact's financial strength supported a significant investment programme during the financial crisis and challenging operating conditions

Te Huka geothermal power station opening (June 2010)

- At 30 June 2010
  - Net debt was $1.35bn
  - Gearing was 32% (net debt to net debt plus equity)
  - Contact had $520m in available credit facilities (of which $106m was drawn)
  - In April 2010 Contact issued $100m of wholesale fixed rate bonds

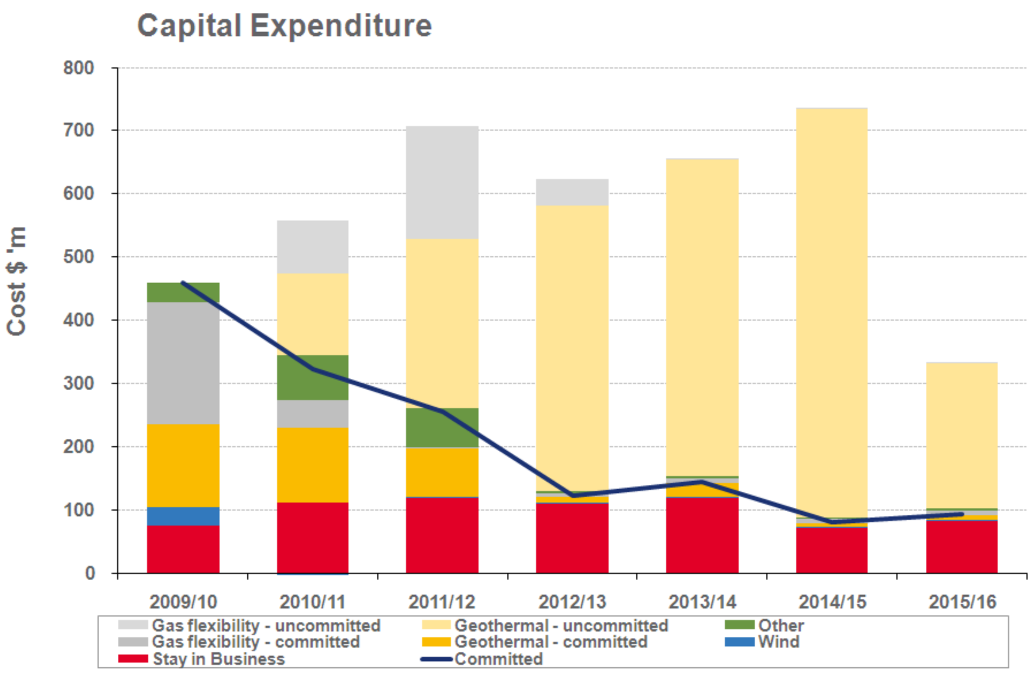
- Profit Distribution Plan has made a significant contribution since its establishment
  - $170m retained by the PDP since its introduction to fund growth assets

# Capital expenditure – reflects Contact's strategy of increasing portfolio flexibility and growth through renewables

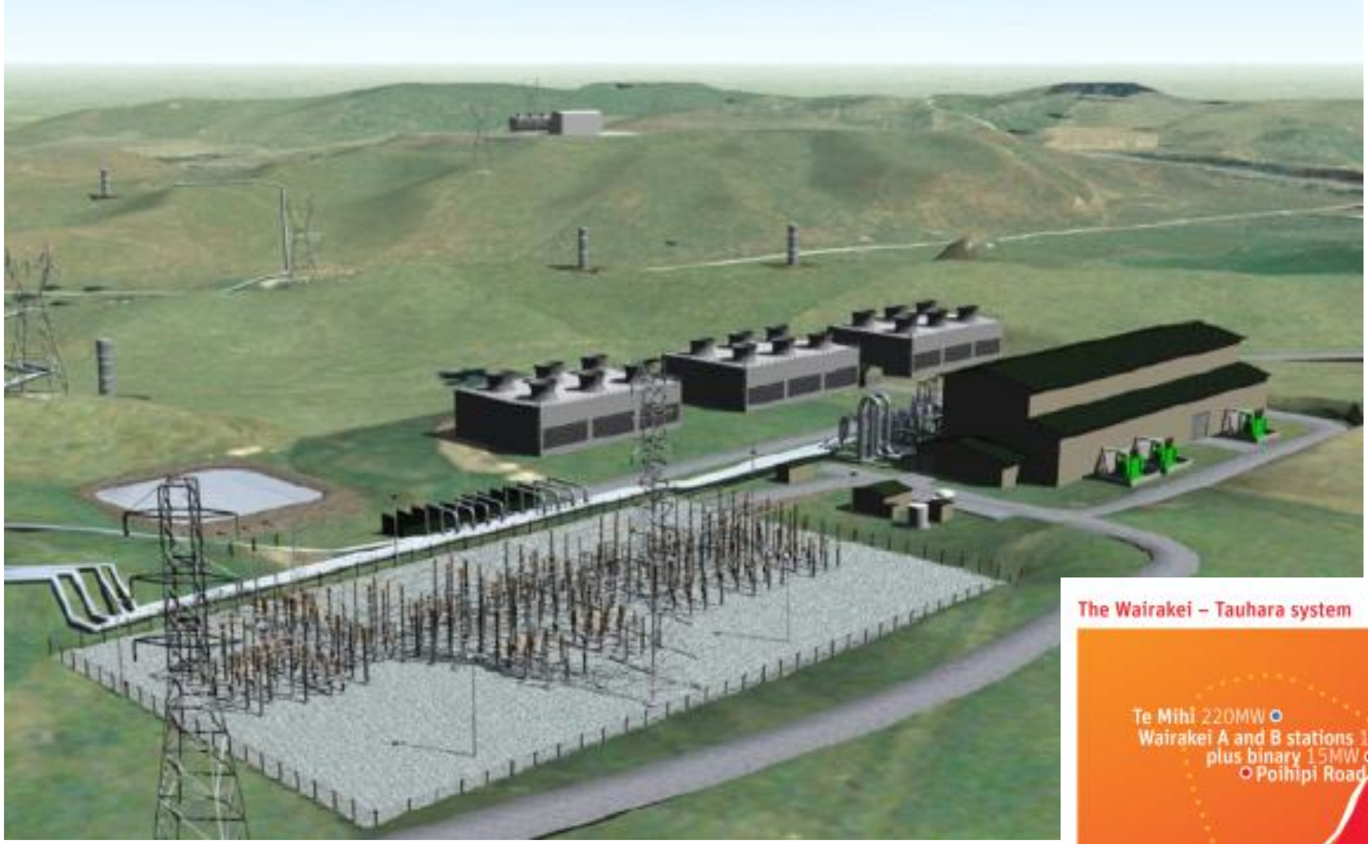
- Stay in business capital expenditure decreased 29% to $76m in FY10
  - Included costs associated with the outages at TCC and Otahuhu B

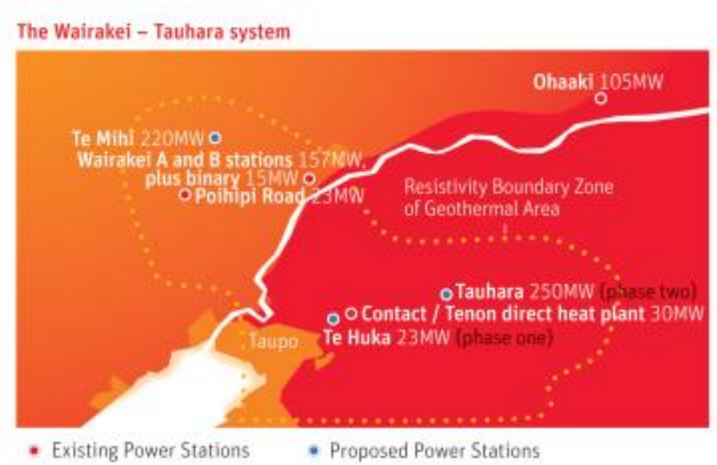
- Growth capital expenditure was $393m, (including capitalised interest) compared with $386m in FY09

- Committed capex includes:
  - Ahuroa gas storage – first stage
  - Stratford peaker plant
  - Other geothermal investment in existing field (wells, steamfield investment etc.)



# Te Mihi: 220 MW – construction tendering

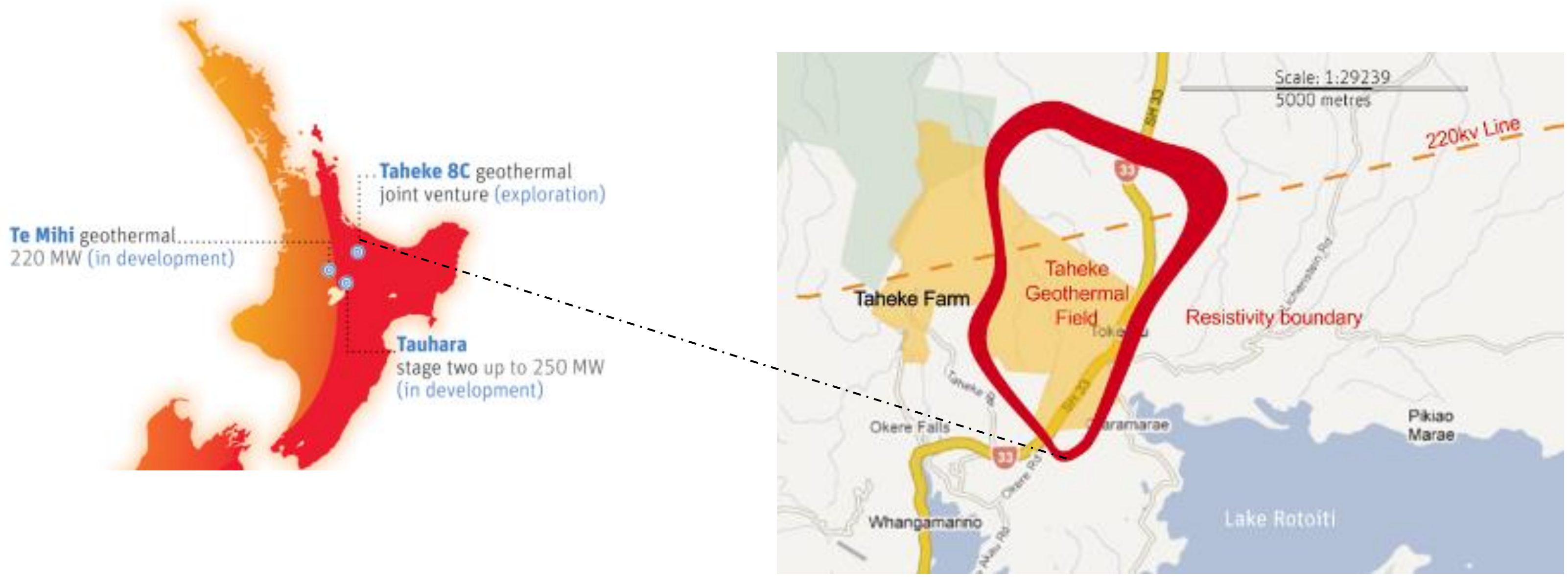




# Tauhara 2: 250 MW – in consenting

- **Contact Energy has filed resource consent applications for its 250 MW Tauhara 2 project**
- **The application is being considered under the new Environmental Protection Authority (EPA) process**
  - Decision is due in early 2011 (9 months following acceptance of the application)
  - Evidence has been submitted and hearings commence in September 2010

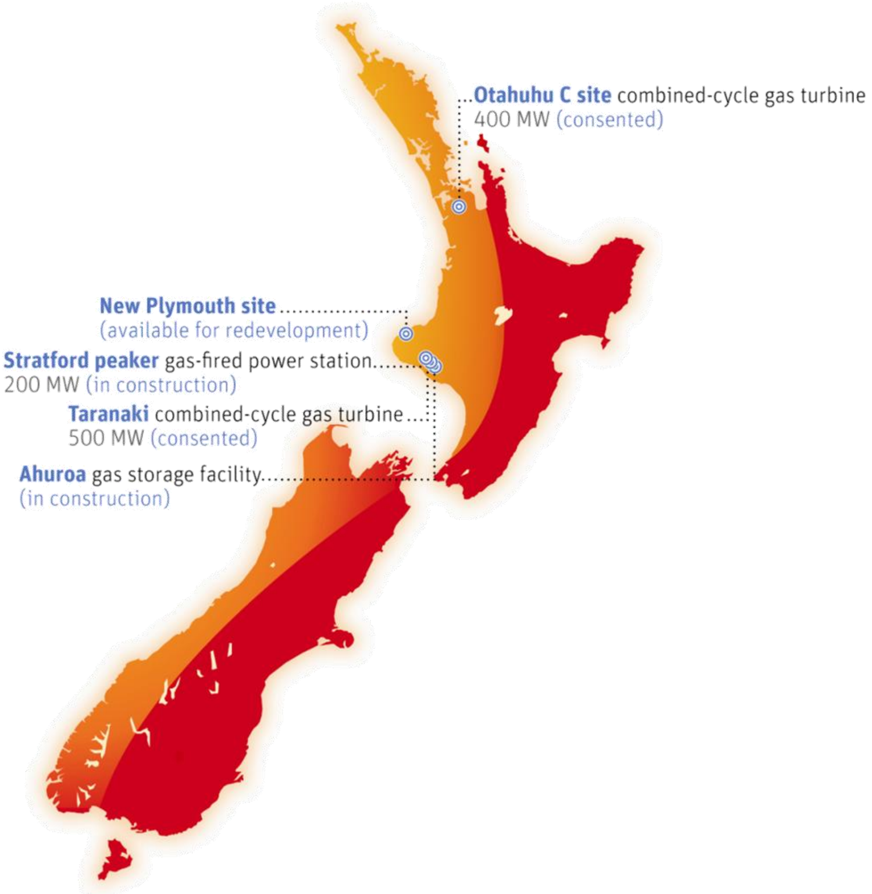
# Taheke




- Contact has been chosen by the Taheke 8C and Adjoining Blocks Incorporation as its joint venture partner to develop a potential geothermal resource
- Represents a significant step forward in Contact's geothermal development programme and in the company's relationships with Maori
- The joint venture will first explore and appraise the resource, including the drilling of exploratory wells
  - First well will commence shortly
- If the exploration and appraisal programme is successful, the parties will jointly develop a new power station

# Gas investments and future options

- With the peakers and storage completed in 2010 Contact is examining other thermal options
  - As wind development continues, additional peaking plant will be required
- Contact has access to consented sites at Otahuhu and Stratford
  - There is also potential to reconsent the New Plymouth site
- Contact is currently seeking to consent an option for a new set of 200 MW peakers
  - Likely to be at an existing thermal site
- If the gas reserve position improves, these sites could also be used for CCGTs



# Hydro and wind developments

## Wind

### HMR (507 MW)

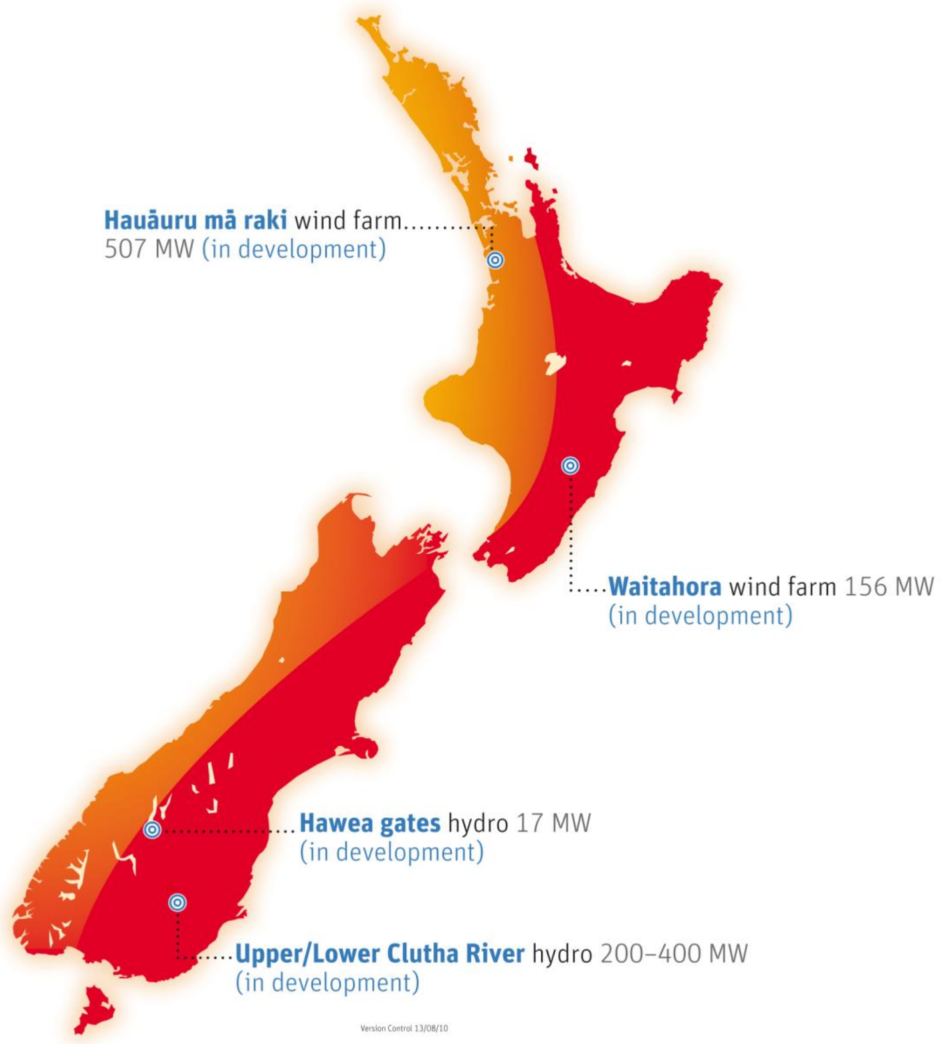
- Submissions to the Board of Inquiry continue
- Hearing is scheduled to recommence on 27 September 2010
- Potential to add further turbines to the project (phase 2)

### Waitahora (156 MW)

- Contact has appealed the refusal to grant the consents to the Environment Court
- Hearing is scheduled for 1 October 2010

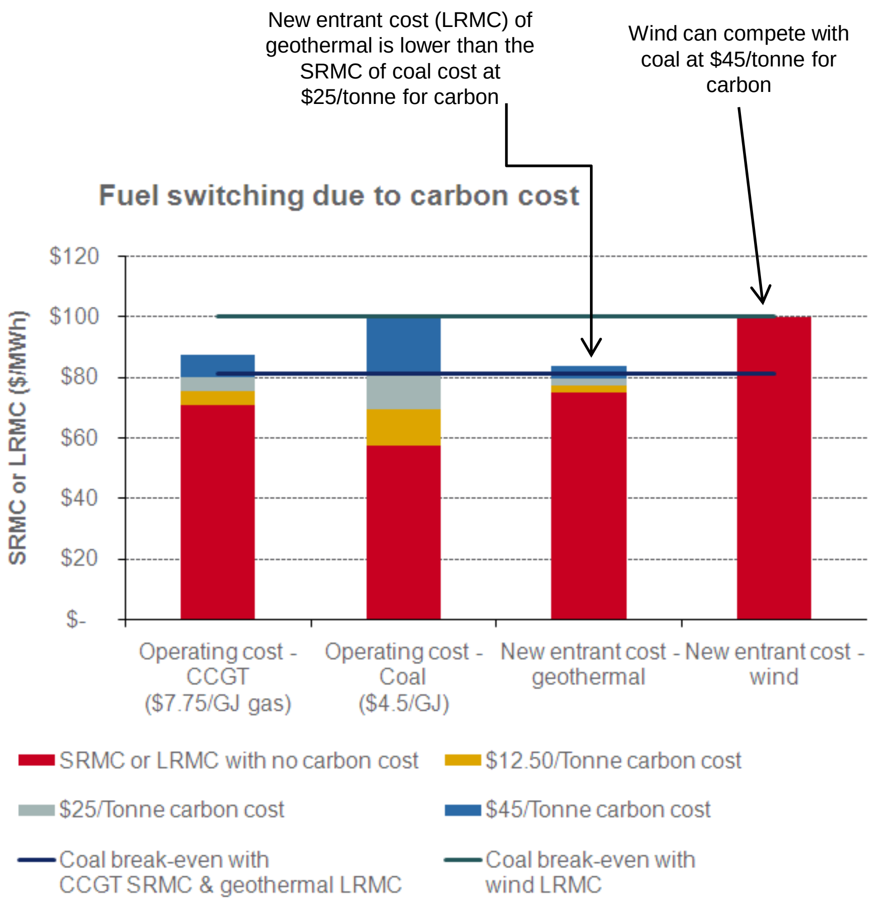
## Hydro

Conceptual design and community engagement underway for options on the Upper and Lower Clutha



# The NZ ETS is a first step in the journey to reduce emissions However, a higher carbon price will be required to make a substantial change to energy sector emissions

- **The ETS is unlikely to materially change emissions from stationary energy**
  - **At $12.50/unit, the thermal merit order doesn't change**
- **At an effective carbon price of ~$25/unit, fuel switching would begin to occur:**
  - **Coal to geothermal and/or gas (at current gas prices)**
  - **And emissions would reduce**



# The prevailing wet conditions in FY10 underscore the rationale and value of Contact's strategy

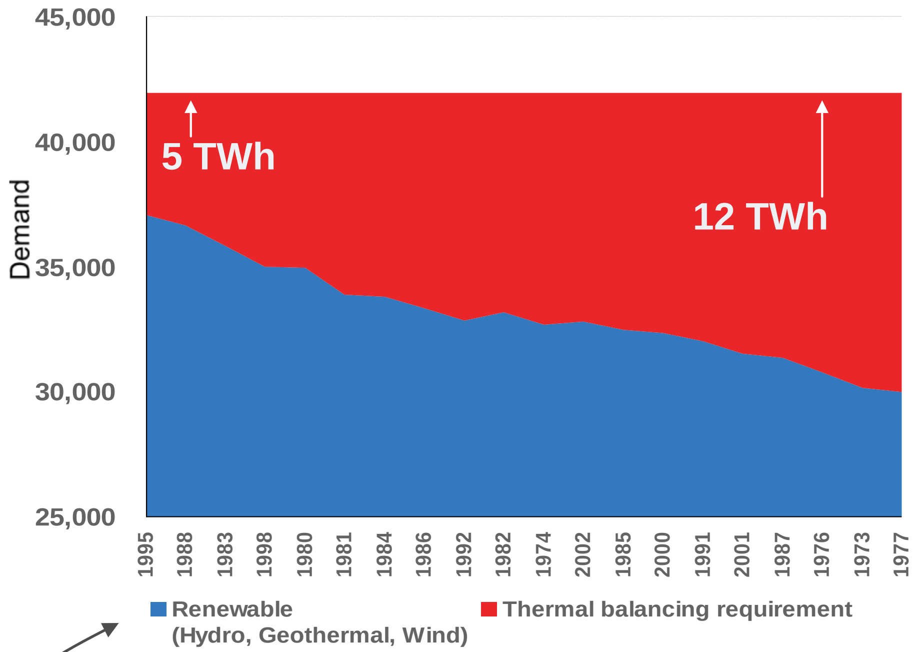
- FY10 result reflects predominantly wet conditions
  - Portfolio inflexibility constrained performance
  - Competition in a low wholesale-price environment was intense, and will continue to be
- Contact executed its strategic plan well – and that will continue…
  - Te Huka completed
  - Peakers and storage complete in first half of FY11
  - Tauhara 2 and wind projects in consenting
  - Te Mihi tendering
- The energy markets are starting to reflect the costs of thermal capacity – and that will continue …
  - Thermal is the only balancing fuel for renewables
  - And therefore critical for a secure energy system in NZ
- Retail prices will continue to rise to reflect increasing network and energy costs

# Outline

# NZ's electricity demand is predominantly met by renewable generation – balanced by thermal plant

## NZ's annual electricity demand

...and how that demand is met depending on how much renewable generation is available in any one year (a very wet year on the left and a very dry year on the right)



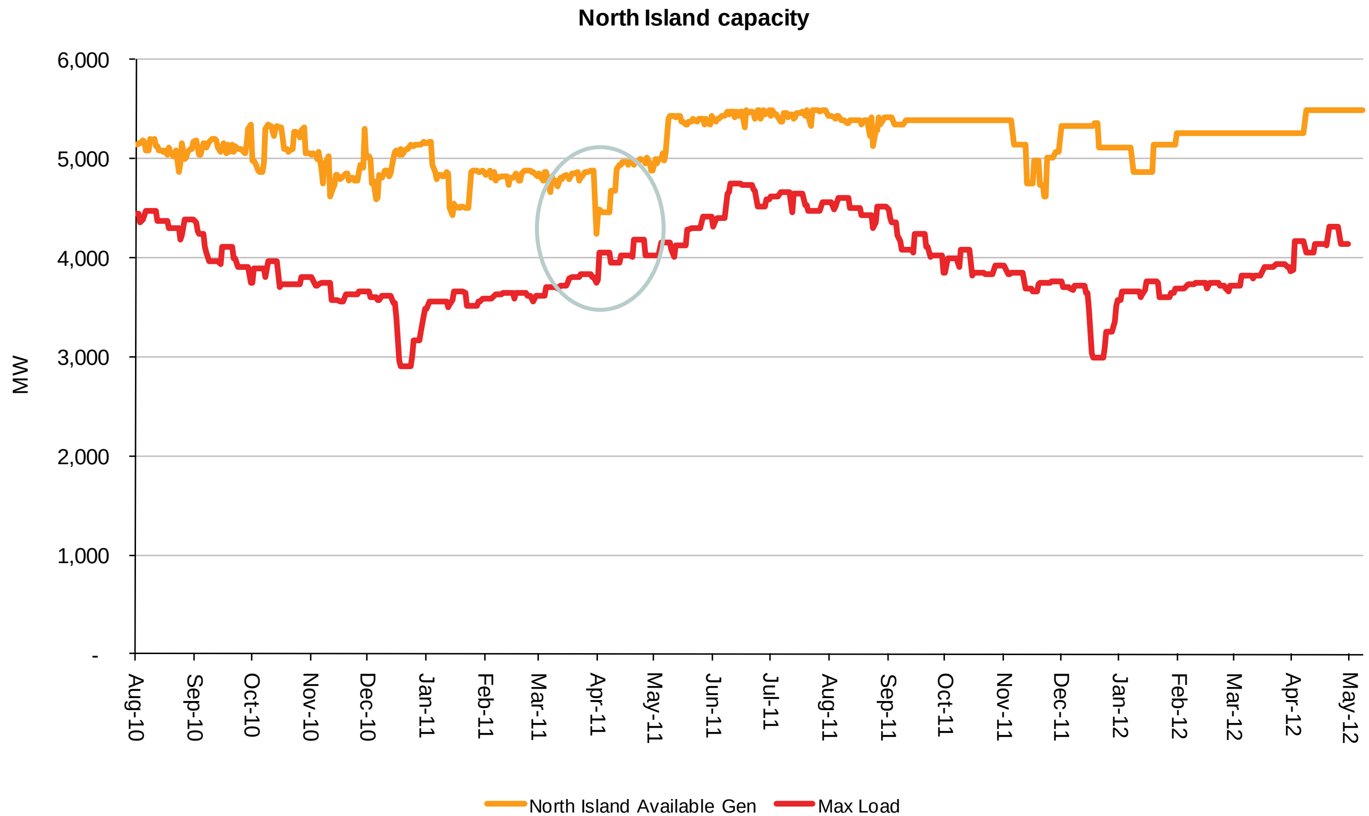

The years represent the actual amount of hydro generation generated

700 MW of wind and geothermal has been added in the last decade

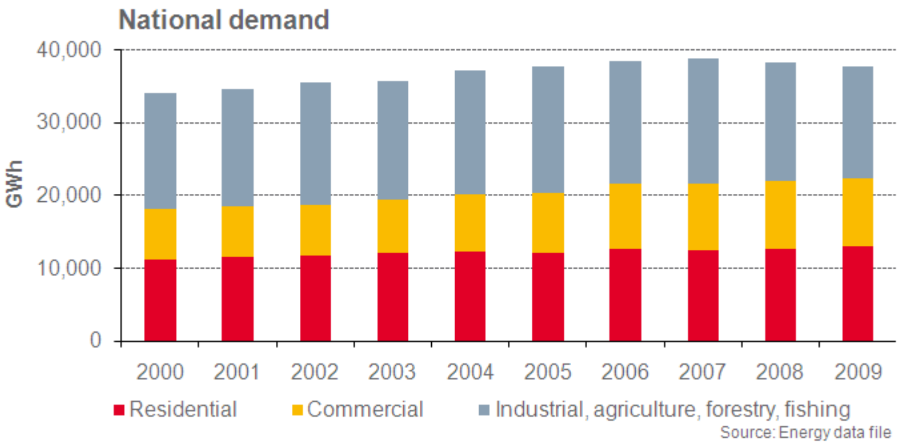
- **Weather-dependent renewable generation requires thermal generation to balance supply**
  - In a dry year, 12 TWh (~2,000 MW on average) of thermal generation is required
  - In a mean year, 8 TWh (~1,300 MW)
  - In a wet year, 4 – 5 TWh (~700 MW)
- **Most of NZ's 2,500 MW of installed thermal capacity is operated by Contact and Genesis**
  - Contact: 800 MW of combined-cycle generation
  - Genesis: 1,000 MW of coal-fired and 400 MW of gas combined cycle
  - Other: 300 MW

# A look at North Island capacity margins confirms the ongoing need for gas-fired capacity

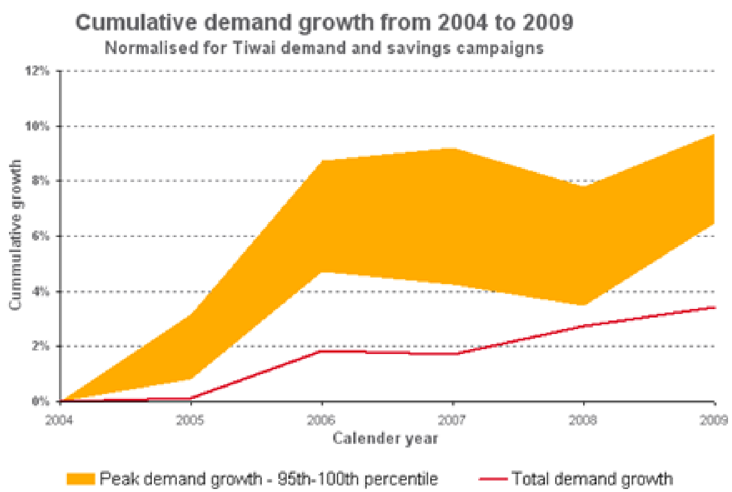
North Island capacity margin would be very low if one CCGT was unavailable or if peak demand grows greater than assumed

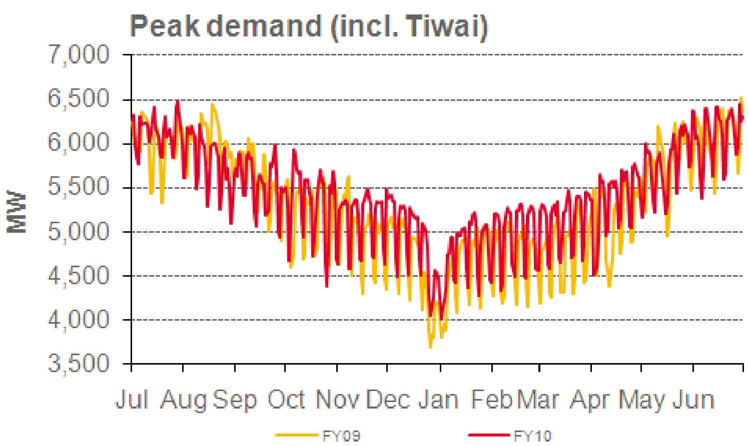


# While demand growth has been limited over the past year, peak demand and price volatility are increasing




- **Over the past two years demand growth has slowed due to the recession**
  - While commercial and residential sectors have grown industrial demand has decreased by over 1,500 GWh
- **Over the past 5 years peak demand has grown nearly 10% while over the same period total demand has grown only 3.4%**
- **As well as the impact of wind, this growth in peak demand has been a significant contributor to increasing price volatility – this increases the cost of capacity to the system and costs of supplying retail customers**

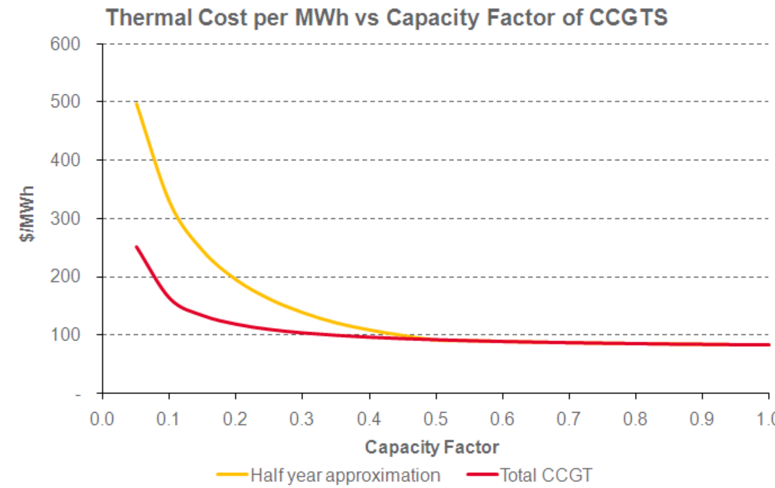


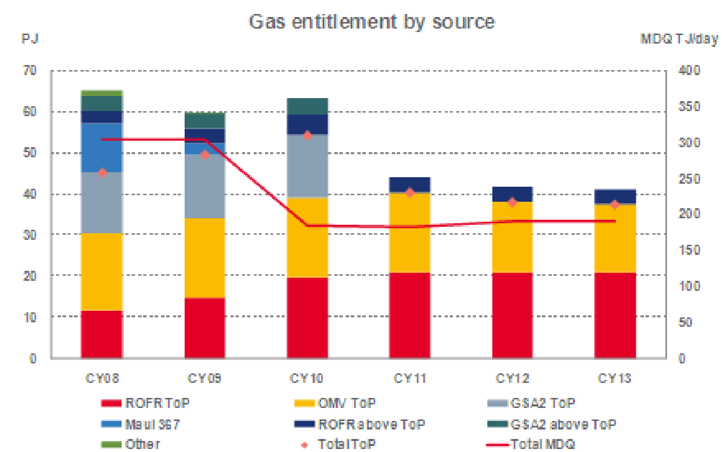



# Improving the performance of the CCGTs has also been an area of focus during the year

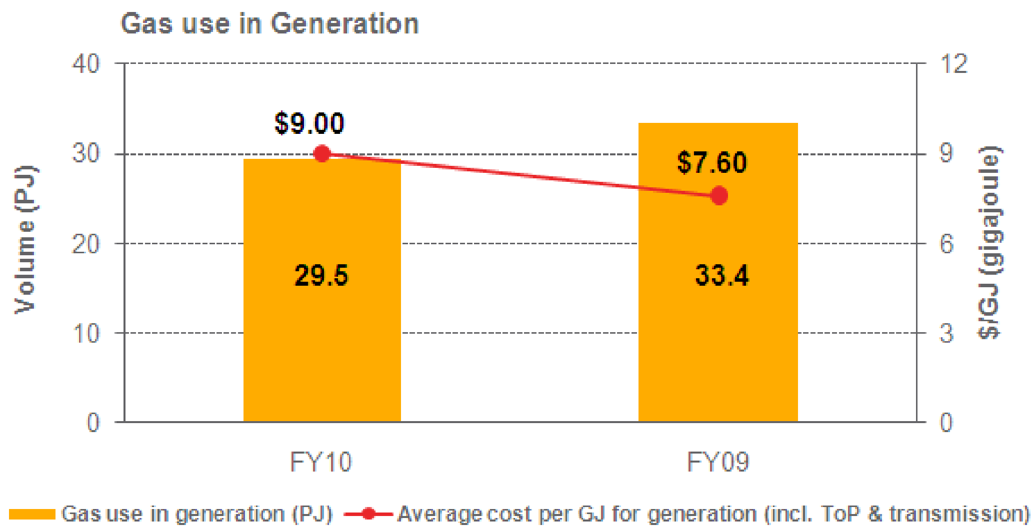
- The primary components of thermal costs are:
  - Take-or-pay gas contracts
  - Long-term maintenance agreements
- Thermal generation costs have increased 17% per MWh
- Contact's thermal strategy is to maximise (i) the flexibility of CCGTs and (ii) the extent to which CCGT costs can be variablised
  - CCGTs will increasingly move to mid-merit operation
- Enabled by:
  - A reduction of Contact's take-or-pay obligations from CAL2011
  - The Stratford peakers; and
  - Ahuroa gas storage

| Breakdown of CCGT generation costs ($ 'm) | FY10 | FY09 | Var | Var (%) |
|---|---|---|---|---|
| Thermal generation volumes | 3,356 | 3,639 | (283) | (8%) |
| Gas costs | (227) | (207) | (20) | (9%) |
| Operating costs | (24) | (21) | (3) | (15%) |
| Transmission, market costs | (6) | (9) | 3 | 32% |
| Depreciation | (58) | (53) | (5) | (9%) |
| **Total costs** | **(315)** | **(290)** | **(25)** | **(9%)** |
| **Total cost ($/MWh)** | **(94)** | **(80)** | **(14)** | **(17%)** |
| **Capacity factor (thermal plant)** | **51.8%** | **56.1%** | **(4.3%)** | |



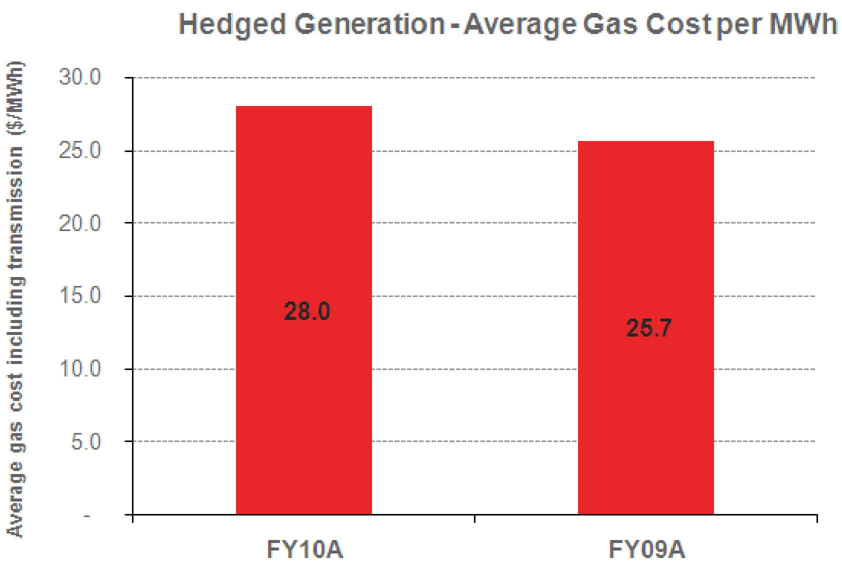



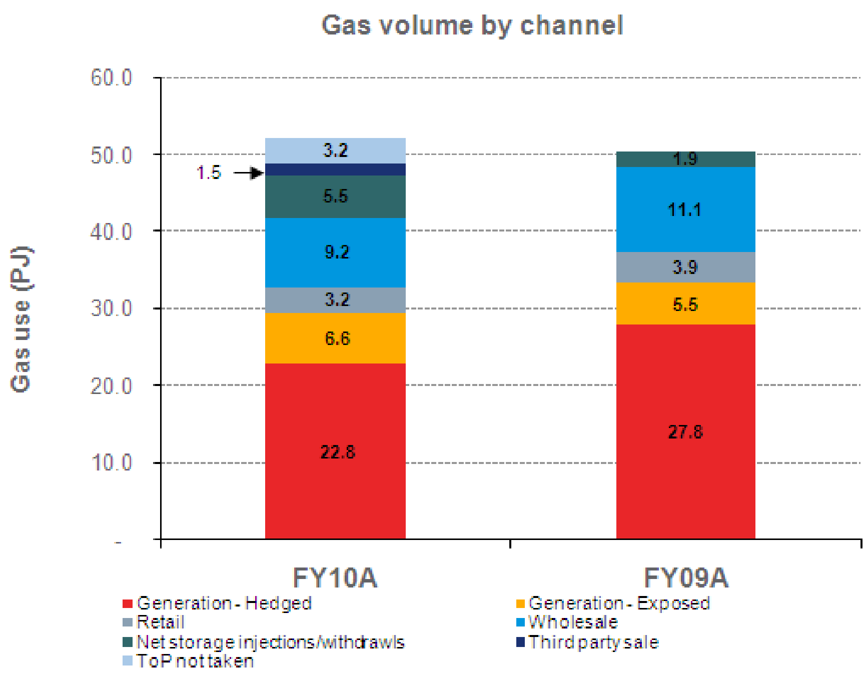
# Gas used in generation and injections into storage



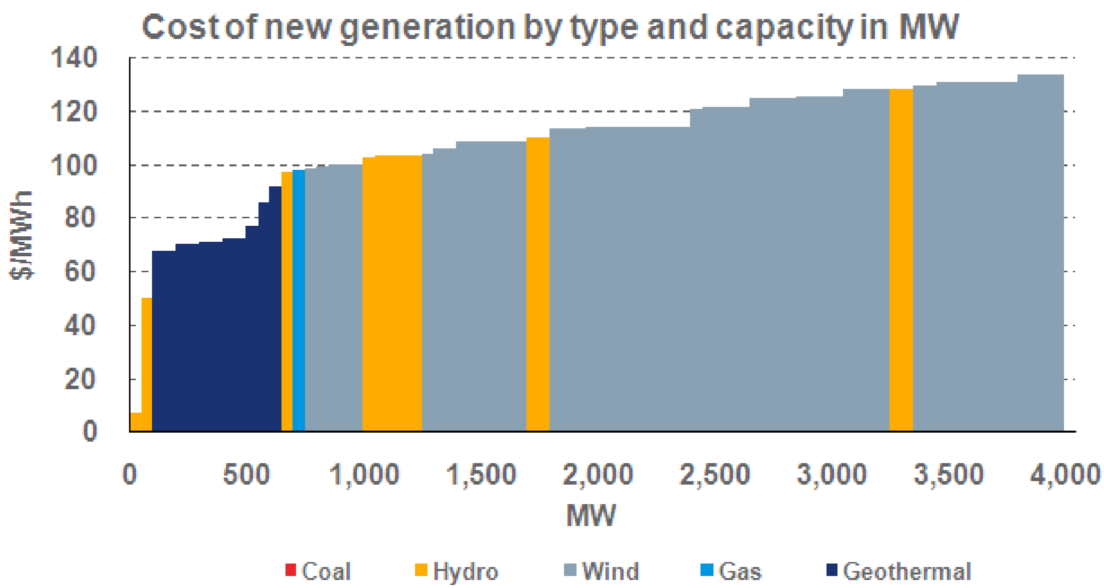

- **The average cost of gas for generation (including transmission) increased by 18% from $7.60/GJ to $9/GJ**
  - Total gas used in generation was 30 PJ, 4 PJ (12%) lower than in the prior period as a result of the decrease in thermal generation
  - The total gas cost for generation (including transmission) was $265m ($11.3m higher than FY09)
  - Gas transmission costs (for gas used in generation) decreased by 13% - average cost per GJ was up 14c/GJ to 66c/GJ
  - During FY10 approximately 5.2 PJ was injected into the Ahuroa gas storage reservoir – as at 30 June 2010 the total volume in the reservoir was ~11 PJ (of which ~6.2PJ is cushion gas)
  - Approximately 3.2 PJ of gas was paid for but not taken and 1.5 PJ was sold at a loss – this added approximately 84c/GJ to the average cost of gas for generation in FY10

# Hedged generation gas costs per unit increased in FY10 due to high hydro conditions constraining gas generation and high gas take or pay



# Geothermal continues to be NZ's best choice for generation investment, and Contact is well positioned to execute when the time is right




- **While geothermal is the most cost effective next source of generation, only some of NZ's resources can be developed**
  - Beyond geothermal, wind and hydro options quickly lift the price required to $100/MWh and beyond

# Generation plant accounting basis has moved from a valuation to a cost valuation basis resulting in a reduction in the accounting value of the fixed asset base

- **The historic policy of revaluing generation plant and equipment commenced when the company was under Crown ownership**
- **Fair value accounting is typically encouraged where there is an active market for such assets and their value can be reliably determined. As New Zealand has a limited market the primary valuation methodology has become discounted cashflow**
- **The 2010 independent valuation range has increased markedly from 2007 as events such as the global financial crisis have introduced volatility into key assumptions**
  - The long life of these assets (up to 100 years) means the valuation is very sensitive to any assumption changes
- **Assessing a single point estimate of fair value within an expanded valuation range is difficult to reliably determine. On the other hand, a cost valuation basis:**
  - is reliable and provides relevant information e.g. transparent return on capital invested
  - Globally these type of assets are normally valued at cost (including Origin)
  - NZX top 15 companies are dominated by cost basis accounting (excluding property companies and companies with regulated businesses)
- **Contact has elected to make a change to a cost basis**

# Impact of restatement of generation plant and equipment

| | FY10 $'000 | FY09 $'000 |
|---|---|---|
| **Impact on Statement of Financial Position** | | |
| Decrease in carrying value of Generation Property, Plant and Equipment | 408,118 | 405,372 |
| Decrease in Deferred Tax Liability | 123,546 | 122,706 |
| Decrease in Shareholder's Equity | 284,572 | 282,666 |
| | | |
| **Impact on Income Statement** | | |
| **Depreciation and amortisation expense before adjustments** | **167,331** | **161,954** |
| - Adjustment due to change in accounting policy | 3,285 | 3,931 |
| - Adjustment due to review of useful lives | (7,172) | - |
| - Adjustment due to change in depreciation methodology for LTMAs | (1,541) | - |
| **Depreciation and amortisation expense after adjustments** | **161,903** | **165,885** |

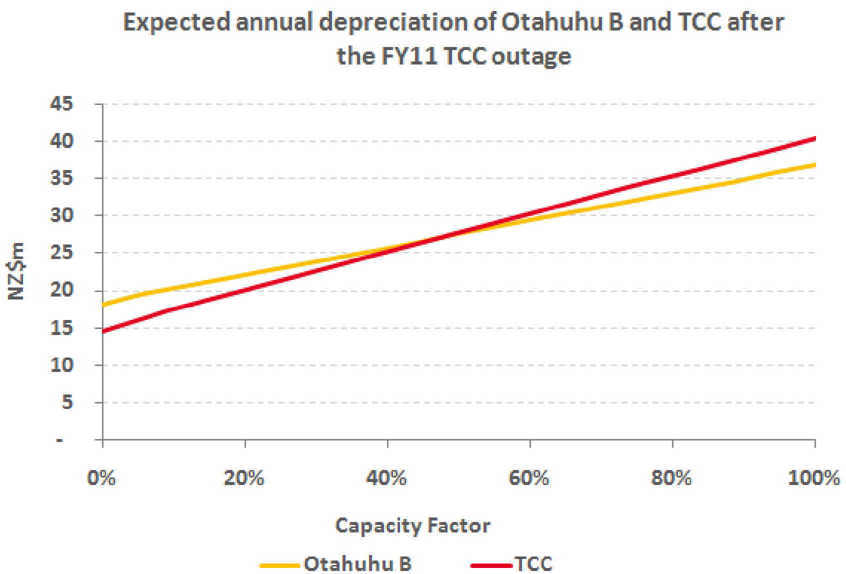
## Depreciation and Amortisation Expense has been adjusted to reflect the normal reassessment of asset lives and change in valuation basis

- **Depreciation and amortisation expense decreased to $162m in FY10 from $166m in FY09**
  - The FY09 depreciation and amortisation has increased $4m to $166m from that previously published due to the voluntary change in accounting policy
  - The year on year decrease is due to:
    - changes in the method of depreciation for the thermal plant LTMA costs which are now based on the level of equivalent operating hours ($1.5m)
    - the impact of re-estimating the useful life of assets from 1 January 2010 ($7.2m)
    - offset by increases associated with the long term maintenance costs for the CCGTs and the geothermal drilling
- **The FY10 outcome is below the previously expected depreciation and amortisation expense of $175m**
  - changes in the method of depreciation for the thermal plant LTMA costs which are now based on the level of equivalent operating hours - ($1.5m)
  - the impact of re-estimating the useful life of assets from 1 January 2010 - ($7.2m)
  - the impact of the voluntary change in accounting policy from valuation to cost - $3.3m
  - changes in the timing of FY10 capital expenditure

# Depreciation for CCGTs will now vary with capacity factor

- **FY11 depreciation and amortisation is expected to increase to approximately $182m although the actual outcome will vary with the output of thermal plants**
  - The commencement of operation of new plant is expected to add $17m of depreciation: Te Huka ($3.6m), Stratford Peaker ($10.9m) and Ahuroa Gas Storage ($2.5m)
  - LTMA costs of thermal plants are now depreciated based on the quantum of equivalent operating hours
    - Otahuhu B FY11 depreciation is forecast at $26m, based on a capacity factor for the plant of 50%. The potential range of forecast depreciation is $18m (0% capacity factor) to $35m (100% capacity factor)
    - TCC FY11 depreciation is forecast at $29m, based on a capacity factor for the plant of 67%. The potential range of forecast depreciation is $23m to $30m
      - The range of TCC depreciation is smaller due to the planned TCC outage in FY11 (any remaining TCC LTMA asset values will be fully depreciated at this time)

- **The graph to the right illustrates how annual depreciation for Otahuhu B and TCC are expected to change with capacity factor beyond the FY11 TCC outage**



# Financial Results Summary

| Key financial information | 12 Months Ended 30 June 2010 $million | 12 Months Ended 30 June 2009 $million | Variance $million | % |
|---|---|---|---|---|
| Operating Revenue and Other Income | 2,164.4 | 2,220.1 | (55.7) | (3%) |
| Operating Expenses (1) | (1,737.4) | (1,774.8) | 37.4 | 2% |
| **EBITDAF (2)** | **427.0** | **445.3** | **(18.3)** | **(4%)** |
| Depreciation and Amortisation | (161.9) | (165.9) | 4.0 | 2% |
| Equity Accounted Earnings of Associates | 3.3 | 3.6 | (0.3) | (8%) |
| Change in Fair Value of Financial Instruments | 4.5 | (57.5) | 62.0 | 108% |
| Removal of New Plymouth Asbestos and Related Costs | (5.6) | - | (5.6) | - |
| Impairment of Gasbridge Assets | - | (2.8) | 2.8 | - |
| Retail Transaction Processing Outsourcing Costs | (3.3) | - | (3.3) | - |
| **Earnings Before Net Interest Expense and Income Tax (EBIT)** | **264.0** | **222.7** | **41.3** | **19%** |
| Net Interest Expense | (56.0) | (62.7) | 6.7 | 11% |
| Income Tax Expense | (53.3) | (44.4) | (8.9) | (20%) |
| **Profit for the Period** | **154.7** | **115.6** | **39.1** | **34%** |
| **Underlying Earnings After Tax (3)** | **149.8** | **158.7** | **(8.9)** | **(6%)** |
| **Shareholders' Equity** | **2,776.8** | **2,659.6** | **117.2** | **4%** |

(1) Includes electricity purchases.

(2) Earnings before net interest expense, income tax, depreciation, amortisation, change in fair value of financial instruments and other significant items.

(3) Underlying earnings after tax removes significant one-off items and the non cash change in fair value of financial instruments.

# Electricity segment result

| Electricity Segment | 12 Months Ended 30 June 2010 $million | 12 Months Ended 30 June 2009 $million | Variance | % |
|---|---|---|---|---|
| Wholesale Electricity Revenue | 539.4 | 594.3 | (54.9) | (9%) |
| Retail Electricity Revenue | 1,301.9 | 1,284.5 | 17.4 | 1% |
| Steam revenue | 17.9 | 12.9 | 5.0 | 39% |
| **Total Electricity Revenue** | **1,859.2** | **1,891.7** | **(32.5)** | **(2%)** |
| Electricity Purchases | (480.8) | (528.9) | 48.1 | 9% |
| Electricity Transmission, Distribution and Levies | (509.7) | (492.5) | (17.2) | (3%) |
| Gas Purchases and Transmission | (265.0) | (253.7) | (11.3) | (4%) |
| Meter lease internal charge (1) | (29.0) | (29.0) | - | 0% |
| Labour Costs and Other Operating Expenses | (187.3) | (174.6) | (12.7) | (7%) |
| **Total Operating Expenses** | **(1,471.8)** | **(1,478.7)** | **6.9** | **0%** |
| **EBITDAF** | **387.4** | **413.0** | **(25.6)** | **(6%)** |
| Depreciation and Amortisation | (153.3) | (153.8) | 0.5 | 0% |
| **Segment Result** | **234.1** | **259.2** | **(25.1)** | **(10%)** |
| | | | | |
| Average Wholesale Electricity Price ($ per MWh) (2) | $52.23 | $56.08 | ($3.85) | (7%) |
| Cost of exposed generation ($ per MWh) | ($29.15) | ($30.76) | $1.61 | 5% |
| Cost of hedged generation ($ per MWh) | ($46.97) | ($44.61) | ($2.36) | (5%) |
| Hedged generation margin ($ per MWh) | $36.13 | $34.47 | $1.66 | 5% |
| Gas Used in Internal Generation (PJ) | 29.5 | 33.4 | (3.9) | (12%) |
| Swaption Generation - Hedged (GWh) | - | 116 | (116) | (100%) |
| Swaption Generation - Exposed (GWh) | 492 | 301 | 191 | 63% |
| Thermal Generation - Hedged (GWh) | 2,767 | 3,349 | (582) | (17%) |
| Thermal Generation - Exposed (GWh) | 887 | 745 | 142 | 19% |
| Geothermal Generation (GWh) | 2,277 | 2,311 | (34) | (1%) |
| Hydro Generation (GWh) | 3,760 | 3,543 | 217 | 6% |
| **Total Generation including Swaption (GWh)** | **10,183** | **10,365** | **(182)** | **(2%)** |
| Average Electricity Purchase Price ($ per MWh) (2) | ($58.95) | ($65.79) | $6.84 | 10% |
| Retail Electricity Purchases (GWh) | 7,959 | 8,203 | (244) | (3%) |
| Generation - Exposed (GWh) | 1,379 | 1,046 | 333 | 32% |
| CfD Sales (GWh) | 845 | 1,116 | (271) | (24%) |
| Retail Electricity Sales (GWh) | 7,674 | 7,703 | (30) | (0%) |
| Electricity Customer Numbers | 477,000 | 479,000 | (2,000) | (0%) |

(1) Intersegment meter lease internal charge of $29.0m is eliminated upon consolidation of the two segments.

(2) This price excludes contracts for differences.

# Other segment result

| Other Segment | 12 Months Ended 30 June 2010 $million | 12 Months Ended 30 June 2009 $million | Variance | % |
|---|---|---|---|---|
| Wholesale Gas Revenue | 75.4 | 72.7 | 2.7 | 4% |
| Retail Gas Revenue | 78.0 | 81.9 | (3.9) | (5%) |
| LPG Revenue | 130.3 | 153.8 | (23.5) | (15%) |
| Meter Leases Revenue | 11.8 | 10.3 | 1.5 | 15% |
| Meter Leases Revenue - Internal (1) | 29.0 | 29.0 | - | 0% |
| Other Revenue | 9.7 | 9.7 | - | 0% |
| **Total Other Segment Revenue** | **334.2** | **357.4** | **(23.2)** | **(6%)** |
| Gas Purchases and Transmission | (131.7) | (145.9) | 14.2 | 10% |
| LPG Purchases | (99.2) | (116.8) | 17.6 | 15% |
| Meter Lease costs | (21.0) | (20.2) | (0.8) | (4%) |
| Market Levies | (1.7) | (2.0) | 0.3 | 15% |
| Labour costs and Other Operating Expenses | (41.0) | (40.2) | (0.8) | (2%) |
| **Total Operating Expenses** | **(294.6)** | **(325.1)** | **30.5** | **9%** |
| **EBITDAF** | **39.6** | **32.3** | **7.3** | **23%** |
| Depreciation | (8.6) | (12.1) | 3.5 | 29% |
| **Segment Result** | **31.0** | **20.2** | **10.8** | **53%** |
| | | | | |
| Gas Sales Wholesale Customers (PJ) | 10.7 | 11.1 | (0.4) | (4%) |
| Gas Sales Retail Customers (PJ) | 3.2 | 3.9 | (0.7) | (17%) |
| Gas Sales LPG Customers (Tonnes) | 70,327 | 77,082 | (6,755) | (9%) |
| Gas Customer Numbers | 64,000 | 67,000 | (3,000) | (4%) |
| LPG Customer Numbers (including franchisees) | 58,000 | 53,700 | 4,300 | 8% |

(1) Intersegment internal meter leases revenue of $29.0m is eliminated upon consolidation of the two segments.

# Segment reporting – details of allocation

- **Contact will now report the following segments:**
  - Electricity (retail and generation)
  - Other (retail and wholesale gas, LPG, meters and other revenue)
- **Adopting an electricity segment will better reflect the integrated nature of the business and remove the volatility in reported results caused by wholesale price movements**
- **The electricity segment covers all electricity related activities**
- **Between the segments there are some core allocations:**
  - Gas take or pay is borne by the electricity segment
  - The loss on wholesale gas sales effected to manage gas take or pay is also allocated to the electricity segment

| Electricity | | Other |
|---|---|---|
| | | |
| Revenue: | | Revenue: |
| Retail MM electricity | | Retail gas sales |
| Retail TOU | | LPG Sales |
| Spot revenue | | Wholesale gas sales |
| CFD revenue | | Other revenue |
| Huntly contract | | Metering revenue (incl transfer charge from retail) |
| Steam revenue | | |
| Storage revenue | | |
| Carbon revenue | | |
| | | |
| Costs: | | Costs: |
| Generation costs | | Gas purchase costs |
| Gas purchased for generation | | Gas customers cost to serve |
| Corporate costs | | Gas customers cost to acquire |
| Wholesale/ trading costs | | Wholesale Gas purchase costs |
| Electricity customers cost to serve | | LPG purchase costs |
| Electricity customers cost to acquire | | LPG customer cost to serve |
| Network charges | | LPG customer cost to acquire |
| LWAP/ GWAP (transmission costs) | | Meter assets costs |
| Carbon costs | | Corporate costs |
| Meter charges to retail (incl transfer cost) | | |
| | | |

# Hedged generation contribution decreased by $3m with a 515 GWh reduction in hedged volumes

| Hedged segment contribution | Units | FY10A | FY09A | Var | Var (%) |
|---|---|---|---|---|---|
| **Hedged generation** | **GWh** | **8,804** | **9,319** | **(515)** | **(6%)** |
| **Transfer price (GWAP)** | **$ / MWh** | **80** | **76** | **4** | **5%** |
| **Hedged generation at GWAP transfer price** | **$ 'm** | **704** | **708** | **(4)** | **(1%)** |
| **Expenses** | | | | | |
| Gas Purchases and Transmission | $ 'm | (247) | (239) | (8) | (3%) |
| Huntly Swaption call cost | $ 'm | (35) | (30) | (5) | (17%) |
| Electricity Transmission | $ 'm | (28) | (37) | 9 | 24% |
| Market Levies | $ 'm | (5) | (5) | 0 | - |
| Other Operating Expenses | $ 'm | (105) | (100) | (5) | (5%) |
| **Total expenses** | **$ 'm** | **(420)** | **(411)** | **(9)** | **(2%)** |
| **Other generation (steam, CFD, ancillary, location costs adj, etc.)** | **$ 'm** | **34** | **24** | **10** | **42%** |
| **Hedged segment contribution** | **$ 'm** | **318** | **321** | **(3)** | **(1%)** |

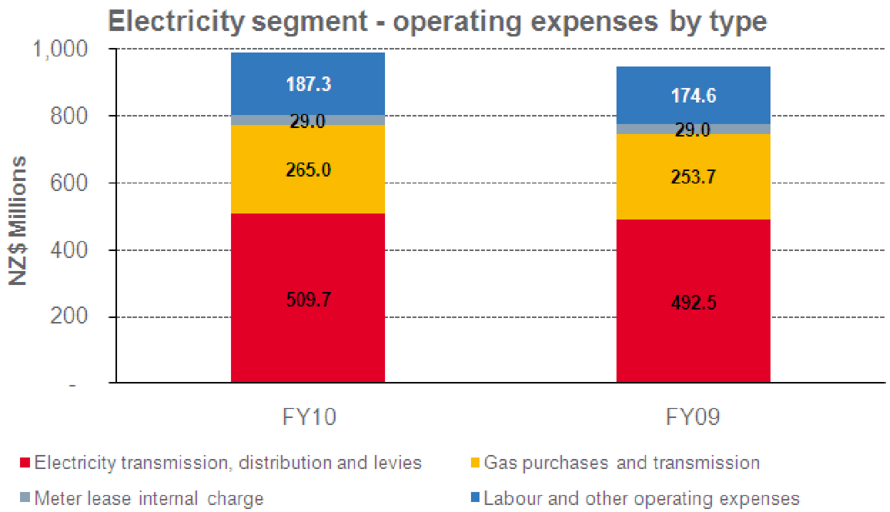
# Exposed generation up $7m (21%) due to higher volumes, offset by lower wholesale prices

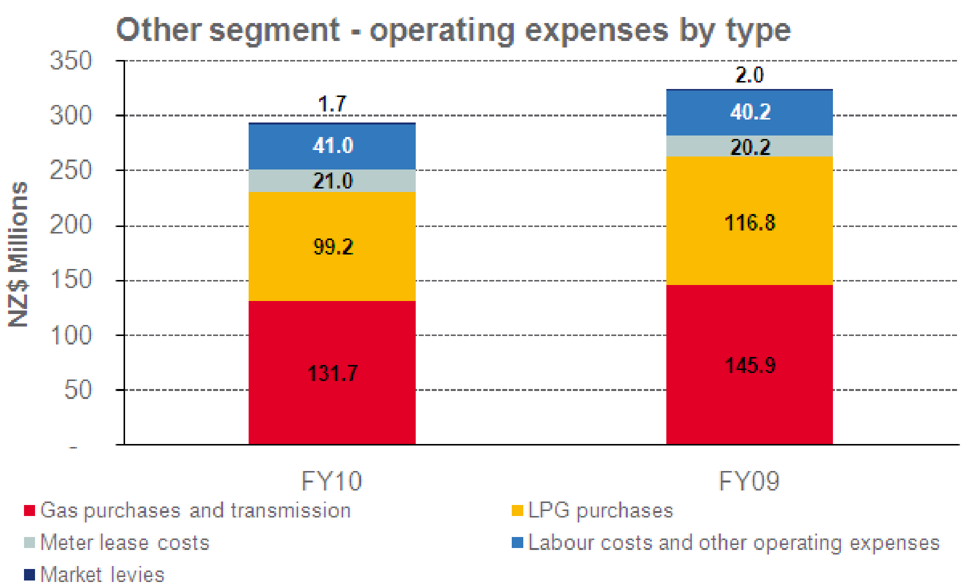
| Exposed segment contribution | Units | FY10A | FY09A | Var | Var (%) |
|---|---|---|---|---|---|
| Exposed generation volume | GWh | 1,379 | 1,046 | 333 | 32% |
| Exposed GWAP | $ / MWh | 58 | 62 | (4) | (6%) |
| Revenue | $ 'm | 80 | 64 | 16 | 24% |
| Expenses | | | | | |
| Gas Purchases and Transmission | $ 'm | (18) | (15) | (3) | (20%) |
| Huntly Swaption call cost | $ 'm | (19) | (14) | (5) | (36%) |
| Electricity Transmission | $ 'm | (3) | (3) | 0 | - |
| Total expenses | $ 'm | (40) | (32) | (8) | (25%) |
| Exposed segment contribution | $ 'm | 40 | 33 | 7 | 21% |

# Retail contribution down by $30m (51%) due to increased costs and intense retail competition – resulting in margin compression

| Retail electricity contribution | Units | FY10A | FY09A | Var | Var (%) |
|---|---|---|---|---|---|
| **Sales** | GWh (ICP) | 7,674 | 7,703 | (30) | (0%) |
| **Revenue** | **$ 'm** | **1,308** | **1,290** | **18** | **1%** |
| Cost of electricity - GWAP | $/MWh | (80) | (76) | (4) | (5%) |
| LWAP / GWAP | % | 109% | 109% | | |
| Cost of electricity - LWAP | $/MWh | (87) | (83) | (4) | (5%) |
| Actual line losses | % | 4% | 6% | | |
| Cost of electricity delivered | $/MWh | (90) | (88) | (2) | (3%) |
| Energy costs | $ 'm | (694) | (680) | (14) | (2%) |
| Transmission and market costs | $ 'm | (474) | (447) | (27) | (6%) |
| Meter lease costs | $ 'm | (29) | (29) | 0 | 0% |
| Retail costs (other OPEX) | $ 'm | (82) | (75) | (7) | (9%) |
| **Total expenses** | **$ 'm** | **(1,279)** | **(1,231)** | **(48)** | **(4%)** |
| **Retail electricity contribution** | **$ 'm** | **29** | **59** | **(30)** | **(51%)** |
| **Retail electricity margin** | **%** | **2%** | **5%** | | |

# Operating expenses by segment (excluding electricity purchases)




- **Electricity segment expenses up $41m (4%)**
  - **Electricity transmission costs increased by $17m ($26m increase for retail offset by a reduction of $9m for generation)**
  - **Gas purchases increased by $11m – lower volume but higher unit cost**
  - **Labour and other operating costs – up $13m**
    - **Customer acquisition costs – up $4m**
    - **Bad debt write offs - up $6m**
    - **Personnel costs - up $5**
    - **Impact of provisions – down $3m**

**Other segment: expenses decreased by $30m (down 9%)**

- **Gas costs down by $14m due to lower sales (1.1 PJ) and lower average cost of gas for wholesale gas sales (20c/GJ reduction)**
- **LPG purchases reduced by $17m due to lower average cost and volume reduction**
- **Labour and other operating costs increased by $1m**